



February 3, 2023

Via E-filing

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20763

Dear Ms. Felice:

The following is attached for paperless electronic filing:

- Testimony and Exhibits of Richard B. Kuprewicz on behalf of Bay Mills Indian Community
- Testimony and Exhibits of Brian J. O'Mara on behalf of Bay Mills Indian Community
- Testimony and Exhibits of President Whitney B. Gravelle on behalf of Bay Mills Indian Community
- Certificate of Service

Sincerely,

Christopher R. Clark
cclark@earthjustice.org

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of Enbridge
Energy, Limited Partnership for Authority to U-20763
Replace and Relocate the Segment of Line 5
Crossing the Straits of Mackinac into a Tunnel ALJ Christopher Saunders
Beneath the Straits of Mackinac, if Approval is
Required Pursuant to 1929 PA 16; MCL 483.1
et seq. and Rule 447 of the Michigan Public
Service Commission's Rules of Practice and
Procedure, R. 792.10447, or the Grant of other
Appropriate Relief

TESTIMONY OF RICHARD B. KUPREWICZ

ON BEHALF OF

BAY MILLS INDIAN COMMUNITY

February 3, 2023

**RICHARD B. KUPREWICZ
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763**

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1 **I. Introduction and Qualifications**

2 **Q. Please state your name, job title, and business address.**

3 A. My name is Richard B. Kuprewicz and I am the President of Accufacts Inc.,
4 headquartered at 8151 164th Ave NE, Redmond, Washington 98052.

5

6 **Q. You previously provided testimony in this matter on behalf of Bay Mills Indian
7 Community (“Bay Mills”), correct?**

8 A. Yes.

9

10 **Q. Did you have a chance to review your previous testimony before submitting
11 testimony today?**

12 A. Yes.

13

14 **Q. Is there anything about your prior testimony that you wish to change today?**

15 A. No.

16

17 **Q. Is there anything in your professional background that is specific to your testimony
18 today that you would like to add?**

19 A. Yes. Beginning in 2002, I was appointed by two separate Governors to the State of
20 Washington to sit on the Washington State Citizen Committee on Pipeline Safety (aka
21 CCOPS) including as its chairman. CCOPS was set up by the state Legislature after a
22 pipeline explosion in Bellingham, Washington, as a committee to advise on all matters
23 relating to hydrocarbon pipelines. Under the Pipeline Safety Improvement Act of 2002,

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1 CCOPS is the only pipeline safety Advisory Committee of its kind in the country that can
2 request timely responses from the federal Secretary of the Department of Transportation
3 on pipeline matters.

4
5 At the national level, starting in approximately 2000, I became involved with the federal
6 Office of Pipeline Safety (OPS) and then PHMSA, representing the public. I was active
7 in representing the public in debate involving proposed federal rulemaking concerning
8 various proposed pipeline safety regulatory matters, such as: Integrity Management,
9 Control Room Management, Pipeline Construction, Leak Detection, and Mainline Valve
10 installation.

11
12 In 2004, I was appointed by the Secretary of Transportation to serve as a voting member
13 representing the public, on the Technical Hazardous Liquid Pipeline Safety Standards
14 Committee (“THLPSSC”) charged with advising PHMSA on proposed pipeline safety
15 regulations. I served approximately 15 years on the THLPSSC.

16
17 In the past two decades, I have submitted and reviewed comments to federal agencies and
18 testified before Congress on such matters as: the Olympic Pipe Line Company failure that
19 occurred in Bellingham, Washington on June 10, 1999; the need for inclusion of Integrity
20 Management in the regulations and the ineffectiveness of the current Integrity
21 Management regulations for transmission pipelines, including Exhibit BMC-50 in which
22 I commented on certain risk assessment approaches being utilized in the United States;

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1 and, more recently, the tragedy related to the Merrimack Valley, Massachusetts gas
2 distribution system failure that occurred on September 18, 2018.

3 I have authored numerous papers on pipeline safety that are in the public domain,
4 including various pipeline incident investigations.

5
6 My updated CV is attached as Exhibit BMC-51.

7
8 **Q. Have you had a chance to review the Commission's July 7, 2022 Order and**
9 **Enbridge's testimony dated October 21, 2022 and January 17, 2023 before**
10 **providing your testimony today?**

11 A. Yes.

12
13 **Q. And did anything within the Commission's July 7 Order or the testimony submitted**
14 **by Enbridge cause you to change your opinions previously expressed in this matter?**

15 A. No.

16
17 **Q. What is the purpose of your testimony today?**

18 A. I was asked by Bay Mills to provide my opinion of the quantitative approach used by
19 Enbridge to justify the risks of its proposed tunnel project and to respond to specific
20 points raised by the Commission in its July 7, 2022 Order.

21
22 **Q. Are you sponsoring any exhibits today?**

23 A. Yes, I am sponsoring the following exhibits:

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- 1 • Exhibit BMC-50 (RBK-2) Accufacts Public Comments on Risk Modeling by
2 Richard B. Kuprewicz
- 3 • Exhibit BMC-51 (RBK-3) Updated Curriculum Vitae of Richard B. Kuprewicz
- 4 • Exhibit BMC-52 (RBK-4) Pipeline Safety Immediate Action Plan, jointly
5 developed by the City of Bellingham and Olympic Pipe Line Company, September
6 10, 1999
- 7 • Exhibit BMC-53 (RBK-5) Pipeline Safety: Pipeline Integrity Management in
8 High Consequence Areas; Final Rule, 49 C.F.R. Part 195.452
- 9 • Exhibit BMC-54 (RBK-6) Pipeline and Hazardous Materials Safety
10 Administration Guidance re: “Pipeline Safety: Potential Low and Variable Yield and
11 Tensile Strength and Chemical Composition Properties in High Strength Line Pipe,”
12 74 Fed Reg 23930 (May 21, 2009)
- 13 • Exhibit BMC-55 (RBK-7) Pipeline and Hazardous Materials Safety
14 Administration Guidance re: “Pipeline Safety: Girth Weld Quality Issues Due to
15 Improper Transitioning, Misalignment, and Welding Practices of Large Diameter
16 Line Pipe,” 75 Fed Reg 14243 (March 24, 2010)
- 17 • Exhibit BMC-56 (RBK-8) Pipeline and Hazardous Materials Safety
18 Administration Corrective Action Order, *In the Matter of TC Oil Pipeline Operations,*
19 *Inc.*, December 8, 2022
- 20 • Exhibit BMC-57 (RBK-9) National Transportation Safety Board Pipeline
21 Investigation Report, “Enbridge Inc. Natural Gas Pipeline Rupture,” May 31, 2022.
- 22 • Exhibit BMC-58 (RBK-10) National Transportation Safety Board, Pipeline
23 Accident Report, Adopted July 10, 2010

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- 1 • Exhibit BMC-59 (RBK-11) Transcript of Hearing before the Subcommittee on
2 Railroads, Pipelines, and Hazardous Materials of the Committee on Transportation
3 and Infrastructure of the House of Representatives re: “The Safety of Hazardous
4 Liquid Pipelines (Part 2): Integrity Management, July 15, 2010
- 5 • Exhibit BMC-60 (RBK-12) Agenda and Notes from Meeting re Line 5 Straits
6 Alternatives Evaluation, January 17, 2018

7

8 **II. Probability Analyses That Are Used to Dismiss Identified Concerns Are Contrary to**
9 **Sound Integrity Management Principles.**

10 **Q. Do you recall Mr. Aaron Dennis’ testimony entered into the record on January 18,**
11 **2022 which asserted there was a one in a million chance that the pipeline will leak**
12 **within the tunnel?**

13 **A. Yes.**

14

15 **Q. And have you had the chance to review Mr. Steven Botts’ response to the**
16 **Commission’s request for information, submitted on January 17, 2023, relating to**
17 **the basis for the “one in a million” number?**

18 **A. Yes.**

19

20 **Q. And finally, have you had a chance to review Mr. John Godfrey’s testimony and**
21 **accompanying report, submitted in this matter on October 21, 2022, in which Mr.**
22 **Godfrey offers a “Probability of Failure Analysis” that attempts to address concerns**
23 **you have raised about the proposed tunnel project?**

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1 A. Yes.

2

3 **Q. What is your reaction to the testimony from these individuals?**

4 A. Each of these witnesses is responding to my observation that, from an engineering
5 standpoint, there is a potential for a release into the Straits from the tunnel by way of a
6 catastrophic explosion by attempting to quantify some aspect of the risk associated with
7 the proposed tunnel project. Mr. Dennis, Mr. Bott, and Mr. Godfrey all assign a numeric
8 probability to various events that could cause a pipeline failure, fire, and explosion. This
9 approach to risk assessment, particularly during the permit approval stage, finds no
10 support in federal pipeline regulations. And, in fact, it is inconsistent with the purpose of
11 the federal integrity management regulations.

12

13 This assignment of probability estimates to known, identified risks during a permitting
14 process is dangerous because it invites complacency. An operator who adopts this
15 approach to the construction and operation of a pipeline will inevitably drive the line
16 toward failure. And, of course, the failure of any pipeline—but particularly a hazardous
17 liquids pipeline in a high consequence area—has the potential for causing fatalities and
18 immense destruction of the surrounding environment.

19

20 The Enbridge witnesses are minimizing the engineering risks of the proposed tunnel
21 project by assigning misleading numeric probability values to certain events which, in
22 turn, communicates a false sense to the Commission and the public that the proposed
23 project is “safe.”

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1 **Q. You stated that the probability assessments offered by the Enbridge witnesses are**
2 **inconsistent with the federal Integrity Management regulations. What are the**
3 **applicable Integrity Management regulations?**

4 A. Integrity Management was incorporated into federal pipeline safety regulations at 49
5 C.F.R. Part 195.452 and was codified and became effective on May 29, 2001. This initial
6 regulation governs Pipeline Integrity Management in High Consequence Areas specific to
7 Hazardous Liquid Operators with 500 or more miles of pipeline, which includes Enbridge
8 and its operation of Line 5 that could affect such areas by a pipeline release.

9
10 “High Consequence Area” is defined in the Integrity Management regulations as a
11 commercially navigable waterway, an area based on high or otherwise concentrated
12 populations, or an unusually sensitive area.

13
14 There is currently pending an Interim Final Rule, with an effective date of February 25,
15 2022, which explicitly clarifies and defines the Great Lakes as unusually sensitive areas
16 for the purpose of compliance with the hazardous liquid integrity management
17 regulations.

18
19 **Q. Describe the role you had in the development of the Federal Integrity Management**
20 **regulations.**

21 A. This question is best answered in two parts:

22 First, in order to understand the development and incorporation of integrity management
23 into federal pipeline safety regulations it is important to understand the tragedy of the

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1 June 10, 1999, Olympic Pipe Line Co. rupture in Bellingham, Washington. Prior to that
2 rupture, release, explosion, and fireball, there were no Integrity Management regulations
3 codified in the United States pipeline safety regulations. The Bellingham event served as
4 a major initiator of the need for pipeline Integrity Management regulations and clearly
5 demonstrated that improvements were needed to enhance pipeline safety regulations.
6 The City of Bellingham quickly brought together three highly specialized pipeline
7 experts, including myself, to investigate and develop a plan with Olympic Pipe Line
8 Company in order to permit that pipeline to restart and to address what appeared to be
9 numerous issues related to the pipeline operation and the associated rupture failure. In
10 cooperation with two senior managers representing Olympic Pipe Line Company, we
11 developed a Pipeline Safety Immediate Action Plan, or PSIAP, that is a matter of public
12 record and attached to my testimony as Exhibit BMC-52.

13
14 Second, following the Bellingham event and a string of other transmission pipeline
15 ruptures and tragedies that occurred following Bellingham, the United States Congress
16 directed the Office of Pipeline Safety (“OPS”) to promulgate federal pipeline safety
17 regulations related to integrity management for most liquid and gas transmission
18 pipelines. I was involved in the development of federal pipeline safety integrity
19 management regulations for both liquid and gas pipeline systems in the United States.
20 The United States adopted a performance-based approach to integrity management that
21 calls on operators to utilize risk assessment to address threats to pipelines before such
22 threats can go to failure. For example, prior to Integrity Management regulation, federal
23 pipeline safety regulation did not require pipeline operators to *ever* reassess their pipeline

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1 integrity after their initial hydrotest following initial construction; the Integrity
2 Management regulations today require that operators continually reassess pipeline
3 integrity on an iterative basis. A close review of current Integrity Management federal
4 regulations, attached to my testimony as Exhibit BMC-53, will demonstrate that Integrity
5 Management, as codified into regulation, is drawn from the PSIAP approach that I
6 developed following the Bellingham tragedy, which is attached as Exhibit BMC-52.

7
8 **Q. What is your understanding of the purpose of the Integrity Management**
9 **regulations?**

10 A. The purpose of the Integrity Management regulations is to set forth the requirement and
11 provide guidance for a pipeline operator to develop its own Integrity Management
12 program for a specific pipeline or pipeline segment that could affect high consequence
13 areas so that the integrity of a pipeline or pipeline segment is assessed in relation to other
14 identified threats on the line. The Integrity Management regulations then set forth
15 performance-based language that requires operators to continually adjust their approach
16 to pipeline safety as the potential consequences of failures increase.

17
18 The Integrity Management regulations provide the *minimum* requirements that an
19 operator must include in its integrity management program for each pipeline segment that
20 could affect a high consequence area.

21
22 Similar to the PSIAP that I helped to develop, the current Integrity Management
23 regulations are meant to rely on a series of checks and balances on various management

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1 processes and approaches that an operator is supposed to utilize throughout the life of the
2 pipeline to prevent failure. Specifically, the operator is tasked with identifying threats
3 unique to the pipeline or pipeline segment, including how those threats can interact
4 together in a way that might cause failure, especially a rupture. The emphasis is on a
5 pipeline integrity-based approach in certain areas which addresses a range of assessment,
6 prevention, and mitigation needs.

7
8 **Q. Why do you believe that the probability analyses offered by Enbridge witnesses are**
9 **inconsistent with Integrity Management principles?**

10 A. If, in its integrity management program, Enbridge utilizes the type of quantitative risk
11 assessment reflected in its testimony in these proceedings (i.e., minimizing risks to the
12 point of them appearing to be nonexistent), then Enbridge will overlook real threats to the
13 safe operation of the pipeline and drive it to failure. This is inconsistent with Integrity
14 Management principles because it slips into what I call “paper management,” or checking
15 boxes to assess a threat and then moving on without evaluating that threat on an iterative
16 basis based on sound engineering principles.

17
18 Although the federal regulations do allow an operator to use quantitative risk assessment
19 as a tool in its Integrity Management program to manage risks, the federal regulations do
20 *not* permit an operator to use quantitative risk assessment to conduct a probability
21 analysis that dismisses known risks as highly unlikely and essentially suggests that the
22 risks can be ignored.

23

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1 **Q. Page 2 of the DNV report states: “Once completed, the Line 5 Replacement Segment**
2 **will be operated and maintained in accordance with Enbridge’s integrity**
3 **management program, which is developed and administered in accordance with**
4 **PHMSA regulations at 49 C.F.R Part 195.” Does this statement alter your opinion**
5 **about the probability analyses?**

6 A. No. Compliance with PHMSA regulations does not assure that a pipeline will not fail; if
7 that were true, we would not see pipeline rupture failures happening across the country,
8 but we do.

9
10 Furthermore, an assurance that there will be compliance with regulations after the
11 pipeline and tunnel have been constructed does not change the fact that the present design
12 of the pipeline and tunnel present several real risks of rupture failure that could lead to a
13 catastrophic event. Those risks should be addressed now when deciding whether to move
14 forward with the project.

15
16 **III. Mr. Godfrey’s Probability Analysis Is Flawed.**

17
18 **Q. Turning specifically to Mr. Godfrey’s testimony and his report titled “Probability of**
19 **Failure Analysis,” what is your opinion of Mr. Godfrey’s testimony and report?**

20 A. Mr. Godfrey’s probability analysis is flawed, misguided, and dangerous. Like the “one-
21 in-a million” testimony of Mr. Dennis and Mr. Bott, it has no basis in federal pipeline
22 safety regulations. In fact, it is flat out contrary to sound integrity management principles.
23 I also have concerns about his methodology – specifically, his use of PHMSA data for the
24 purposes of conducting a probability analysis during a permitting process and his cherry-

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1 picking of data to support his conclusions. Finally, I have specific concerns about how he
2 and the other Enbridge witnesses have failed to address adequately concerns I have about
3 the risk of pipeline failure at the girth welds and, especially at the heat-affected zones; the
4 reliance on Enbridge's computer monitoring for releases; and, how human error increases
5 the possibility of a catastrophic event within the tunnel.

6
7 **a. Mr. Godfrey's probability analysis is inconsistent with Integrity Management**
8 **Principles.**

9 **Q. What is the basis for your opinion that Mr. Godfrey's probability analysis is**
10 **inconsistent with Integrity Management Principles?**

11 A. Mr. Godfrey's analysis is inconsistent with integrity management principles for the
12 reasons stated above in Section II of my testimony. But I would add that quantitative risk
13 analysis, which is, in essence, what Mr. Godfrey attempts to do, was considered and
14 rejected during the development and codification of the federal pipeline integrity
15 management regulations. Quantitative risk analysis is not part of our federal regulatory
16 scheme, and for good reason. In practice, an approach that quantifies the risk of an
17 event—here, the failure of the pipeline within the tunnel—creates what I refer to as a
18 “kill threshold,” or a prescriptive limit on the amount of death or destruction caused by an
19 event. There is no such limit or threshold established in U.S. federal pipeline safety
20 regulations. This approach, as presented by Enbridge's witnesses, is unenforceable in the
21 operation of a pipeline, and particularly dangerous when used during the permitting stage
22 of a project when engineering concerns should be addressed.

23

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1 **Mr. Godfrey's reliance on PHMSA data is methodologically flawed and**
2 **inconsistent with the data's intended purpose.**

3 **Q. What concerns do you have about the methodology employed by Mr. Godfrey?**

4 A. Mr. Godfrey relies on data maintained in the PHMSA database. Critically, the reportable
5 incident data provided to PHMSA by operators is neither verified nor regulated. Often, it
6 only captures the operator's initial version of events relating to a pipeline incident. To get
7 a complete understanding of the causes of a particular incident, one would have to look at
8 other sources of information, including the results of investigations conducted by the
9 National Transportation Safety Board (NTSB) and other investigatory bodies. The NTSB
10 investigations which follow a pipeline rupture tend to identify *both* a most probable cause
11 and contributing factors, such as operator error, the totality of which can better inform a
12 risk assessment. For example, many recent pipeline ruptures—e.g. the Olympic Pipe Line
13 rupture in Bellingham, Washington; Enbridge's Line 6B rupture in Marshall, Michigan;
14 or, the Line 10 rupture in Hillsboro, Kentucky—were all later determined to have causes
15 that were more complex than initially reported or understood.

16
17 Furthermore, I do not agree with Mr. Godfrey's selection of relevant data points. He
18 excludes certain incidents and includes others, cherry-picking data points to support his
19 conclusions. But arguing about the selection of data points is really beside the point,
20 because the entire analysis is misguided for the reasons I have stated earlier.

21

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1 can result in a combination of girth weld and, more importantly, HAZ failure from
2 cracking, usually resulting in a full bore pipeline rupture from abnormal loading threats.

3
4 **Q. And based on your review of the proposed tunnel project, there will be girth welds**
5 **and heat affected zones located within the confines of the tunnel, correct?**

6 A. Yes. The pipeline segment within the tunnel will be a series of pipe segments joined by
7 girth welding. What is unusual and especially risky for the proposed pipeline segments
8 within the tunnel is that the pipeline will be installed on rollers and anchored in the
9 middle of the tunnel to permit pipeline movement that will place unusual abnormal
10 loading on the pipeline's girth welds and HAZs, which can result in full bore pipeline
11 rupture.

12
13 **Q. Why does Mr. Godfrey's probability analysis not alleviate your concerns about a**
14 **failure of the pipeline at the girth welds or heat affected zones within Enbridge's**
15 **proposed tunnel project?**

16 A. The risk of failure at the girth welds or heat affected zones in the X-70 pipeline should be
17 addressed through sound Integrity Management analysis and procedures that go well
18 beyond the API Std 1104 for girth welding and heat treatment of pipe, not dismissed with
19 a probability analysis. A sound approach would look at girth welds and HAZs both as it
20 interacts with other threats (e.g., movement of the pipe on the rollers), and not at a fixed
21 point of time (a hypothetical year 1 and year 99) but as the pipeline changes and moves
22 throughout its lifetime. While Exhibit A-13, which is relied on by Mr. Godfrey,
23 recognizes that the pipeline will be installed on rollers to provide for thermal expansion

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1 and movement, Mr. Godfrey does not take into account the interactive threats between
2 the unusual and abnormal loading that this design will place on pipeline's girth welds and
3 HAZs. Enbridge has not demonstrated it is taking the unique threat of catastrophic failure
4 at the girth welds or heat affected zones seriously.

5
6 And, very specifically, Mr. Godfrey's probability analysis fails to address and
7 inappropriately dismisses the concerns I raised about girth welds in recently constructed
8 X-70 pipe. The probability analysis minimizes the point that even with modern pipelines
9 we still see failures in new X-70 pipe. The report's analysis is based on data from
10 pipelines with installation dates of 2000 or later to reflect modern girth welding practices.
11 But, as noted in my previous testimony, the risk of girth weld and HAZ failures in X-70
12 pipeline in recently built pipelines is well-documented by rupture failures.

13
14 The JIR report, which I previously testified about, was an industry-sponsored report that
15 recognized the problem of girth weld failures in X-70 pipes. The report documented a
16 known concern that PHMSA had issued advisories about. In 2009, PHMSA issued an
17 advisory stating,

18 PHMSA is issuing an advisory bulletin to owners and operators of natural
19 gas pipeline and hazardous liquid pipeline systems. This bulletin advises
20 pipeline system owners and operators of the potential for high grade line
21 pipe installed on projects to exhibit inconsistent chemical and mechanical
22 properties. Yield strength and tensile strength properties that do not meet
23 the line pipe specification minimums have been reported. This advisory

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1 bulletin pertains to microalloyed high strength line pipe grades, generally
2 Grade X-70 and above. PHMSA recently reviewed metallurgical testing
3 results from several recent projects indicating pipe joints produced from
4 plate or coil from the same heat may exhibit variable chemical and
5 mechanical properties by as much as 15% lower than the strength values
6 specified by the pipe manufacturer.

7
8 The full text is attached to my testimony as Exhibit BMC-54.

9
10 Further, in 2010, PHMSA issued another advisory stating,

11 PHMSA is issuing an advisory bulletin to notify owners and operators of
12 recently constructed large diameter natural gas pipeline and hazardous
13 liquid pipeline systems of the potential for girth weld failures due to welding
14 quality issues. Misalignment during welding of large diameter line pipe may
15 cause in-service leaks and ruptures at pressures well below 72 percent
16 specified minimum yield strength (SMYS). PHMSA has reviewed several
17 recent projects constructed in 2008 and 2009 with 20-inch or greater
18 diameter, grade X70 and higher line pipe. Metallurgical testing results of
19 failed girth welds in pipe wall thickness transitions have found pipe
20 segments with line pipe weld misalignment, improper bevel and wall
21 thickness transitions, and other improper welding practices that occurred
22 during construction. **A number of the failures were located in pipeline**
23 **segments with concentrated external loading due to support and**

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1 **backfill issues.** Owners and operators of recently constructed large
2 diameter pipelines should evaluate these lines for potential girth weld
3 failures due to misalignment and other issues by reviewing construction and
4 operating records and conducting engineering reviews as necessary.

5 The full text is attached to my testimony as Exhibit BMC-55 (emphasis added).

6
7 These advisories and the JIR report refute the notion that modern pipelines will not fail,
8 particularly due to abnormal loading. Indeed, the December 07, 2022 Keystone pipeline
9 failure is the most timely example that even recently manufactured and constructed
10 pipelines fail and cause catastrophic damage to the environment. The Keystone pipeline
11 in Kansas was grade X-70 whose construction was completed in 2011. It failed on
12 December 07, 2022 spilling as of the latest reported, approximately 14,000 barrels
13 (despite being shut down after 7 minutes post-alarm) and the extent of the damage
14 remains unknown. The Commission should request from the Secretary of Transportation
15 color photos of the recent Keystone X-70 pipeline rupture before the pipeline was
16 removed for forensic analysis. I believe the photos will highlight the potential for failure
17 at the girth welds and HAZ from abnormal loading forces in recently constructed X-70
18 pipe. For all these reasons, Mr. Godfrey's dismissive approach does not alleviate the
19 concerns I have about girth welds and heat affected zones. This event is discussed in the
20 Pipeline and Hazardous Materials Safety Administration Corrective Action Order for the
21 Keystone Pipeline, attached as Exhibit BMC-56.

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The NTSB investigative report on the Line 10 rupture, which is attached to my testimony at Exhibit BMC-57, concluded that Enbridge was aware of the risk of its girth weld rupturing as early as 2018. The NTSB stated:

“Like all analyses, tensile strain demand and capacity calculations include certain modeling assumptions and associated uncertainties that must be considered in any decision-making that relies on the results. Notably, Enbridge’s pre-rupture analyses did not appropriately consider uncertainties such as weld defects, changes in the slope and direction of the landslide that could increase the susceptibility of the girth welds to fracture, acceleration of the landslide, or the response of the pipeline to these factors. As a result, *Enbridge determined that no immediate action was needed to mitigate the identified geohazard threat and therefore did not take necessary actions before the rupture.*”

Q. To support its conclusions, the probability analysis states that “[a]ll alarms generated by the CPM are addressed in accordance with Enbridge Control Center procedures. These procedures require the immediate shutdown and sectionalizing of the pipeline if the Control Center is unable to rule out the possibility of a leak or rupture within ten minutes of the start of the alarm.” Does the fact that Enbridge’s Control Center procedures indicate a shutdown of a pipeline within 10 minutes from the start of an alarm alleviate your concerns about the risk of a catastrophic explosion occurring in the tunnel?

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1 A. No.

2

3 **Q. Please explain.**

4 A. First, my immediate reaction is that I've heard and seen this statement before.

5

6 The 10-Minute Rule was adopted by Enbridge after the Line 3 rupture in Grand Rapids,
7 Minnesota in March, 1991. During that incident, personnel in Enbridge's Edmonton
8 Control Center interpreted the SCADA alarms and indications to a condition of column
9 separation and instrument error and continued to pump oil into the ruptured line for more
10 than an hour until the release was eventually recognized.

11

12 Following that incident, Enbridge stated in its response to OPS that a revision to the
13 operation maintenance procedures manual was adopted stating:

14 "If an operator experiences pressure or flow abnormalities or unexplained
15 changes in line conditions for which a reason cannot be established within
16 a 10-minute period, the line shall be shut down, isolated, and evaluated
17 until the situation is verified and or [sic] corrected."

18 Exhibit BMC-58 (Marshall Michigan NTSB report).

19

20 On July 15, 2010, I testified before the House of Representative's Committee on
21 Transportation and Infrastructure, Subcommittee on Railroads, Pipelines, and Hazardous
22 Materials on matters related to The Safety of Hazardous Liquid Pipelines: Integrity
23 Management. Also present was Mr. Richard Adams, Enbridge's Vice President of U.S.

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1 Operations, Liquids Pipelines. During an exchange that asked Mr. Adam's about
2 Enbridge's ability to respond to a possible release, Mr. Adam's stated:

3 "Certainly, our response time from our control center can be almost
4 instantaneous, and our large leaks are typically detected by our control
5 center personnel. They have enough experience and training that with
6 usually a leak of any size they can view that there is a change in the
7 operating system, and there are provisions that if there is uncertainty they
8 have to shut down within a period of time."

9 Exhibit BMC-59 (Congressional Testimony) at page 39.

10
11 Just 10 days later, on July 25, 2010, Line 6B ruptured in Marshall, Michigan. Despite the
12 10-Minute rule being on the books, the Line 6B rupture was not discovered or addressed
13 by Control Room Personnel for more than 17 hours during which two pipeline startup
14 attempts were performed adding to oil release volume.

15
16 The reliance by Mr. Godfrey and the other Enbridge witnesses on the 10-Minute Rule is,
17 in my opinion, an inadequate response to the concerns I have raised about the risk of a
18 catastrophic explosion in the tunnel. When human error occurs in the implementation of
19 the 10-Minute Rule, something that has occurred on numerous occasions since the rule
20 was first implemented by Enbridge, then the Rule will not prevent a catastrophe from
21 happening. Following my prior testimony, the Commission addressed this point and
22 requested that Enbridge specifically describe whether its secondary leak detection system
23 incorporates an automatic shut-down system. Enbridge has not provided plans for such a

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1 system that would automatically shut down Line 5 and close remotely controlled
2 mainline valves spanning the tunnel segment should hydrocarbon indicative of a mainline
3 release be remotely detected within the tunnel. Enbridge's reliance on the 10-Minute
4 Rule is short-sighted, ignores a history of noncompliance with its own Rule, and ignores
5 practical consequence that within those 10 minutes—or longer—product will continue to
6 quickly flow through the rupture leading to the explosive conditions that I described in
7 my previous testimony.

8
9 **Q. What other aspects of Enbridge's proposed plan for monitoring the safety**
10 **conditions in the tunnel are prone to human error?**

11 A. The Tunnel Design and Construction Report (Exhibit A-13) highlights the design systems
12 within the tunnel, but no Enbridge witness has identified how each design is subject to
13 human error. In my experience, human error often occurs (as it did in Line 6B, Line 10,
14 and in the Bellingham event) because the control room operator misinterprets the alarms
15 and continually restarts the pipeline allowing more product to flow through a ruptured
16 pipeline. Each of the following design features documented in Exhibit A-13 are subject to
17 human error:

18
19 *First*, Enbridge relies heavily on its use of In Line Inspection tools (ILI tools). However,
20 the data collected from the ILI tools is analyzed by engineers, and the analysis of the data
21 collected from the ILI tools is subject to operator error as demonstrated by the too many
22 pipeline rupture investigations I have investigated. In addition, the use of ILI tools, even

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1 with advanced technology approaches, has proven to be ineffective at assessing pipeline
2 girth welds and HAZ threats.

3
4 *Second*, Enbridge states that the “tunnel communications systems will provide both radio
5 and wired communication between the tunnel and the above ground control room.” The
6 radio system will be provided via a distributed antenna communication system and relies
7 on a person in the above ground control room to answer the radio. The fixed
8 communication systems will be provided via mine telephones and relies on a person in
9 the above ground control room to answer the telephone. The fixed communications
10 system is subject to human error.

11
12 *Third*, Enbridge’s reliance on CPM and historical data is prone to human error. CPM
13 based on pressure loss has been demonstrated in many liquid pipeline ruptures to be
14 highly ineffective at timely identifying pipeline ruptures and is further subject to human
15 error. Here, liquid pipeline ruptures have repeatedly demonstrated that pressure loss is not
16 a timely method to quickly identify liquid pipeline ruptures, especially given the unique
17 elevation profile of Line 5 involving the tunnel within the Straits of Mackinac.

18
19 The second layer of the pipeline leak detection is an “external leak detection system
20 installed within the tunnel and is comprised of gas monitors and liquid hydrocarbon
21 detection systems.” The hydrocarbon detection systems are monitored by Enbridge
22 employees and response indications/alarms are subject to human error. One aspect of the
23 hydrocarbon detection system includes a strobe light mounted on the outside wall near

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1 the doorway which is to be activated when gas is detected. Monitoring, and responding
2 to, a strobe light from a distance is certainly subject to human error.

3
4 *Fourth*, Enbridge states that, in the event of a product release, “the leak detection system
5 will be activated to provide an audible and visual alarm” to persons in the Enbridge
6 Control Center. Response to the audible and visual alarms in the event of a product
7 release is subject to human error—something which occurred in the Line 6B rupture
8 when the control room operators misinterpreted or ignored the audio and visual alarms
9 and continued to pump product through the pipeline.

10
11 *Fifth*, Enbridge states that, in the event of a fire while maintenance personnel are in the
12 tunnel, the ventilation system will require manual control of the fan plant based on
13 information supplied by the personnel about the location of the fire and the egress
14 direction they choose. Further, once personnel are safely evacuated a decision will need
15 to be made by the local control center whether to secure the air lock and switch-off the
16 ventilation system. This procedure, too, is subject to human error.

17
18 **IV. Additional Response to Commission’s July 7, 2022 Order**

19
20 **Q. You reviewed the Commission’s July 7 Order, correct?**

21 **A. Yes.**

22
23 **Q. On page 38 of the July 7, 2022 Order the Commission stated, “However, he**
24 **[Kuprewicz] asserts that “[t]he more stringent Class 1 Division 1 specifications**

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1 **intended to avoid the source of an electrical ignition would be a more appropriate**
2 **measure” to prevent an explosion.” Order at pg. 38 (emphasis added). What is your**
3 **response?**

4 A. I did not testify that any change in the electrical specifications could prevent an
5 explosion. It is a dangerous view to think that any measure would prevent an explosion.
6 For the reasons I previously stated, the use of Class I Division 1 specifications is critical,
7 and is the far better practice given the unusual confining space of a tunnel, although its
8 importance is being downplayed consistent with Enbridge’s approach to all other threats.
9 An integrity management approach should never assume that a failure will be prevented,
10 especially in the confines of a large concrete tunnel with a pipeline moving hydrocarbons,
11 especially HVLs such as propane.

12
13 **Q. Also on page 38 of the July 7, 2022 Order, the Commission stated, “He [Mr. Dennis]**
14 **contends that for an explosion to occur, three *extraordinary events* must occur**
15 **simultaneously;” and, “Mr. Dennis also asserts that, in the *unlikely event* that**
16 **product is released into the tunnel, there will be leak detection systems and**
17 **procedures to shut down the pipeline;” and, “Thus, even in the *extremely unlikely***
18 ***scenario* of a release which then went undetected long enough to create an explosive**
19 **atmosphere, there is still not an ignition source within the tunnel.” Order at pg. 38**
20 **(emphasis added). What is your response?**

21 A. As a certified experienced process safety management engineer, I have observed too
22 many situations where the three factors come together resulting in catastrophic
23 explosions. Responses by Enbridge personnel and their representatives about the

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1 effectiveness of shutting down and isolating the mainline across the tunnel represent a
2 serious misunderstanding of pipeline hydraulics that permits oil release even when such
3 response actions are quickly implemented on a liquid transmission pipeline. Mr. Dennis's
4 assertions demonstrate a serious lack of experience with hydrocarbon releases and
5 explosions.

6
7 **Q. Have you reviewed any other documents that support your testimony today?**

8 A. Yes, I reviewed Exhibit BMC-60. This document includes notes indicating that
9 representatives of Enbridge discussed the use of probability calculations to articulate the
10 unlikelihood of certain events occurring. This exchange (e.g., "the state wants to hear one
11 in a million") supports my position that Enbridge witnesses are assigning misleading
12 numeric probability values to certain events which, in turn, is used to communicate a
13 false sense to the Commission and the public that the proposed project is "safe."

14
15 Sound engineering and risk assessment principles require that you separate marketing of
16 a product—here, the proposed tunnel—from the engineering risks associated with the
17 project. Combining the two, as Enbridge has done, leads to what I have labeled over the
18 decades as "Space Shuttle Syndrome," which as I previously testified, refers to what
19 occurs when people ignore or underestimate risk to drive to a preordained decision to the
20 point where they dismiss or ignore very real risk in favor of going forward with a project.

21
22 **Q. Does this complete your testimony?**

23 A. Yes.

EXHIBIT BMC-50

Accufacts Inc.
“Clear Knowledge in the Over Information Age”

Testimony of Richard B. Kuprewicz
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Date: October 16, 2018

**To: <http://www.regulations.gov>
Docket No. PHMSA-2018-0050
Pipeline Safety: Gas and Hazardous Liquid Pipeline Risk Models**

Re: Accufacts Comments on Risk Modeling Technical Report Draft 1, dated May 9, 2018

Accufacts has reviewed the above draft report posted to the docket (“Report”) and has the following general recommendations and observations. My feedback is based on involvement and/or experience in investigating too many recent gas and liquid transmission pipeline failures and tragedies following the issuance of transmission pipeline integrity management program (“TIMP”) federal pipeline safety regulations in the early 2000s. There is something definitely wrong in the way many in the industry are utilizing risk assessments to address threats of concern that end up failing, well before claims of predicted “conservative” assertions about their approaches. The number of transmission pipeline ruptures shortly after inline inspection (“ILI”) misuse is raising a credibility gap with the public that will only be compounded if risk assessment models and ILI are oversold as to their capability.

My comments are focused specifically on transmission pipelines.¹ While Accufacts often has access to investigative information not in the public domain, my observations below are based on information readily available in the public domain. There has obviously been a lot of effort placed in developing the Report on risk modeling. The Report appears to meet the objectives of the mission statement, especially in the areas of PHMSA recommendations, subject to the caveats I identify below. Given the number of transmission pipeline failures following TIMP regulatory enactment, there is clearly something still not quite right or complete in too many risk assessment approaches being utilized in various TIMP procedures in the U.S., including various environmental assessments related to proposed new transmission pipelines. For TIMP, I believe, the risk assessment approach was not intended to be overly complex or complicated. It appears too many companies have failed to grasp the simplicity of the process safety management approach embodied in TIMP.

¹ Distribution Integrity Management Program, or DIMP, regulations were developed after years of discussion, becoming effective in mid 2011 though many companies were already implementing DIMP protocols. DIMP regulations incorporate additional performance metrics reporting that has rendered DIMP more effective than first generation TIMP safety regulations.
Accufacts Inc.

Concerning the Report, Accufacts has the following recommendations:

- 1. The simple purpose of risk assessment in TIMP regulation needs clarification.**
- 2. The strengths and weaknesses of each of the four risk model techniques should be clearly summarized.**
- 3. Further explanation as to why quantitative system or probabilistic modeling approaches are not necessarily better, is warranted.**
- 4. More effort is needed in detailing pipeline rupture dynamics and associated transients that can increase risks.**
- 5. Additional regulatory detail should be added to easily demonstrate why facility safety risks are considerable less than mainline pipeline risks.**

Expanding on the above recommendations in further detail:

- 1. The purpose of risk assessment in TIMP federal regulation was to be forward looking to avoid low frequency, but high consequence, transmission pipeline failures (i.e., ruptures).**

TIMP regulation was an attempt to apply process safety management approaches to address too many management shortcomings causing transmission pipeline systems to go to rupture failure. While a review of historical records could possibly indicate management failings, TIMP's primary focus is looking forward by requiring a management team to identify pipeline threats, periodically properly assess such threats, and remediate such anomalies well before failure. I believe risk assessment was to be utilized to aid pipeline management in prioritizing how quickly they should remediate such anomalies before they go to defect (failure). The number and extent of recent transmission pipeline failures clearly demonstrates that some pipeline management teams are exercising very poor risk assessments and judgment.

Pipeline ruptures are low frequency high consequence events reflective of pipe fracture mechanics, and are not modeled well using probabilities from historical databases. Such reported databases may serve some limited purpose in identifying certain trends or possible gaps in safety regulation utilization, but such backward looking historical databases are not the intent of TIMP regulations. Efforts to quantify such events based on history can easily misrepresent (i.e. underestimate or ignore) very real risks to a particular pipeline segment, and set up pipeline management for a very big, and usually very expensive, surprise. TIMP

regulation is not focused on general risks spread over many pipelines, but is intended to address very real risks associated with specific threats on an individual pipeline segment. Attempts to normalize risk probabilities over industry-wide databases can also seriously understate or misrepresent risks, especially as they relate to a specific pipeline's rupture risk. Given the misuse of risk assessments in integrity management programs that I have investigated that set the pipelines up for rupture, both in liquid and gas transmission pipelines, I believe the Report would serve all parties well by briefly explaining what the simple intent of risk assessment is in TIMP.

2. Any one of the four risk assessment modeling approaches presented in the Report is capable of preventing low frequency high consequence events, if prudently applied.

The relative assessment/index model risk approach was utilized by most pipeline operators recently experiencing transmission pipeline rupture failures. While there can be a wide range in approaches using the four methods to prevent pipeline failure, the truth of the matter is that any of these risk model approaches can be effective if properly applied. Such ruptures raise valid questions about the adequacy or completeness of integrity management programs and the application of risk modeling. I believe a closer examination of those pipeline operators will easily demonstrate a very embarrassing amateur, even dismissive, attitude toward this technique that could easily be addressed. Such incomplete risk assessments were clearly not the intent of TIMP, and raise serious questions about certain pipeline operators' approaches/commitments concerning TIMP and the adequacy of current TIMP regulation. It is clearly understood that further regulatory guidance is required to improve what I would call a first generation TIMP regulation concerning risk assessment utilization, and more importantly, its purpose in integrity management. I would suggest that the recommendations sections in the Report incorporate additional guidelines as to strengths and weaknesses specific to each of the four risk model techniques, to assist in their proper selection and use.

3. The more complex approaches associated with quantitative and/or probabilistic risk modeling are not necessarily better.

While it is true that the more quantitative risk model approaches can be more versatile, especially when it comes to consequence identification, there can be great danger in their use if they fail to adequately capture appropriate risk parameters that can threaten a particular pipeline segment. This is especially true if the modeling approach fails to properly consider all threats facing a particular pipeline segment as well as additional interactive threats or

human factors that can markedly increase risks on a particular pipeline segment.² More data isn't necessarily better if key data is wrong, incomplete, or not applicable, to the specific pipeline segment, or if the threat is assessed improperly.

The purposes of TIMP risk assessment were to establish priorities for proper assessment on those segments that were most at risk of rupture failure where catastrophic failure could have higher consequences. Regarding TIMP, after approximately fifteen years we should be well beyond the initial baseline phase of risk assessments. Pipeline operators are supposed to be able to understand risks on their pipeline most likely to rupture. The risk modeling report needs to provide additional discussion/guidance on those pipelines where key data is missing that increases risks. Risk assessment should not be utilized to “guess” or fill in key data such as that associated where the pipe qualities are unknown (usually associated with “grandfathered” pipelines that have not undergone proper hydrotesting). The San Bruno rupture tragedy should underscore the dangers of assigning inappropriate assessment techniques not designed to address the threat risks in a specific pipeline, resulting in gravely understating risks.³ More discussion on how to establish risk for unknowns such as grandfathered pipe is warranted, as there are still too many pipelines that have not undergone prudent hydrotesting assessment.

Too often I have seen complex risk assessment approaches utilized to justify poor pipeline siting or operation/maintenance practices, such as inadequate or inappropriate inline inspection. While I have observed parties from both sides of an argument attempting to justify their positions with extremely poor quantitative risk assessments, such discussions fail to recognize one important fact. **In the U.S. there are no acceptable risk thresholds defined in pipeline safety regulations, as pipeline safety and pipeline siting, for example, are handled under different regulations or processes, if at all.** The purpose of risk assessment under TIMP regulation is fairly simple. Risk assessment approaches identified in TIMP were to identify all possible threats and apply appropriate assessment approaches and/or operational changes to avoid such threats reaching failure, especially rupture.

On more complex pipeline systems there may be a need to rank higher risk segments, especially those segments missing key data, to assure timely assessment and proper remediation. The common failing in these more complex approaches is in their lack to adequately identify and address threats specific to a particular pipeline segment, and then to

² Subject matter experts and experienced pipeline integrity management experts should be well aware of the higher risks associated with interactive threats as discussed in ASME B31.8S-2004, Section 2.2 Integrity Threat Classification.

³ NTSB, “Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010, Accident Report NTSB/PAR-11/01,” adopted August 30, 2011.

prudently and timely utilize the assessment method(s) best able to evaluate such threat(s). I place little credibility in probability statistics extrapolated from PHMSA databases to try and identify a particular pipeline operator as “good” or “bad” on a specific pipeline. While PHMSA has made great strides in making incident information available and public, there are serious limitations to such self-reported databases, especially if they cannot be independently audited for accuracy. Overutilization of incomplete or inaccurate databases in an attempt to assign probability risks to fill in important missing data on a specific pipeline segment can be very foolish and reckless. The old adage still applies, “garbage in equals garbage out,” in what I call the misinformation age. Misuse of volumes of inappropriate information coming at decision makers 24/7 can get in the way of an informed decision. Risk assessment should be utilized to assist decision makers, in getting key data, not get in the way by concealing key information that might be missing to avoid a prudent decision.

4. Rupture transient dynamics are still not well captured.

Given the many failings I have observed concerning pipeline rupture, I must comment on a major weakness related to pipeline rupture release dynamics that is showing up in numerous quantitative or probabilistic risk analysis approaches. Rupture release dynamics result in a significant increase in the rate of release of hydrocarbon from a pipeline rupture. While not properly outlined in regulation, the large openings associated with pipeline ruptures usually reduce the pipeline system “resistance pressure curve,” causing upstream pump or compressors to run out on their flow curves, increasing the flow rates into the pipeline and out the rupture site.⁴ This transient effect adds to release rates well beyond pump/compressor flows out of the rupture site as the compressed hydrocarbon inventory in the pipeline unpacks adding to the flow rate out of the rupture site.

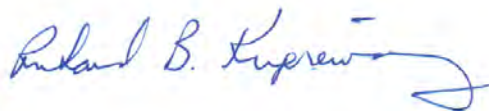
Such rupture transient dynamics cause additional confusion in remotely identifying rupture releases via control room or automatic pressure loss indication, that can markedly delay automatic pipeline shutdown equipment, if installed. These interactions can seriously increase the actual response time to initiate pipeline shutdown, isolation, and emergency response, further adding to release volumes and risks. The modeling report appears to attempt to address this transient phenomenon under the classification of human factors, but further detail, I believe, is warranted in this important area given its tendency to significantly increase risks. It is worth noting that modeling ruptures as a “full bore” failure may not be adequate nor sufficient, especially for liquid hydrocarbons, given the pipeline system transients associated with pipeline rupture.

⁴ Based on extensive experience in rupture investigations, 49CFR§194.105 defining worst case discharge calculation approaches for oil spill response plans, in all probability, understates oil that can be released from liquid transmission pipeline ruptures.

5. Additional regulatory details should be added showing why facility safety risks are considerably less than transmission mainline pipe safety risks.

Lastly, TIMP regulation rightfully focuses on mainline pipe, especially given the additional prescriptive pipeline safety regulations that currently apply to pump and compressor stations. Storage tank farms present a different operation, and are usually not covered by federal pipeline safety regulation intended to address transmission pipelines and pipeline related facility safety issues. From a safety perspective, pipeline mainlines present greater risks to the public than pump or compressor station facilities for various reasons. Any risk model approach should be able to easily demonstrate a major difference (many orders of magnitude reduction in safety risks) for facilities when compared to transmission pipelines. There may be other issues such as environmental or emission related areas that are of possible public concern related to facility siting decisions, but safety should not be one of them. Adding some of the prescriptive safety regulatory requirements that increase pipeline facility safety by reducing risks I believe is warranted and should be included in the Report dealing with such infrastructure risk discussions.

In summary, considerable efforts have been spent in developing the Report. I would suggest that additional clarifications about the suitability and intent of risk assessment be added to assist pipeline operators, regulators, and the public to understand risk assessment applicability in TIMP. I would especially caution against the use of risk approaches that try and predict future operation, especially if guesses have to be made to fill in missing key data related to pipeline integrity. I believe such prediction efforts were never intended, given the forward looking process management intent of TIMP regulation to address threats before they reach the level of causing pipeline rupture.



Richard B. Kuprewicz
President,
Accufacts Inc.

EXHIBIT BMC-51

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Profile:

As president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

Employment:**Accufacts Inc.****1999 – Present**

Pipeline regulatory advisor, incident investigator, and expert witness on all matters related to gas and liquid pipeline siting, design, operation, maintenance, risk analysis, and management.

Position: President
Duties: > Full business responsibility
> Technical Expert

Alaska Anvil Inc.**1993 – 1999**

Engineering, procurement, and construction (EPC) oversight for various clients on oil production facilities, refining, and transportation pipeline design/operations in Alaska.

Position: Process Team Leader
Duties: > Led process engineers group
> Review process designs
> Perform hazard analysis
> HAZOP Team leader
> Assure regulatory compliance in pipeline and process safety management

ARCO Transportation Alaska, Inc.**1991 - 1993**

Oversight of Trans Alaska Pipeline System (TAPS) and other Alaska pipeline assets for Arco after the Exxon Valdez event.

Position: Senior Technical Advisor
Duties: > Access to all Alaska operations with partial Arco ownership
> Review, analysis of major Alaska pipeline projects

ARCO Transportation Co.**1989 – 1991**

Responsible for strategic planning, design, government interface, and construction of new gas pipeline projects, as well as gas pipeline acquisition/conversions.

Position: Manager Gas Pipeline Projects
Duties: > Project management
> Oil pipeline conversion to gas transmission
> New distribution pipeline installation
> Full turnkey responsibility for new gas transmission pipeline, including FERC filing

Four Corners Pipeline Co.

1985 – 1989

Managed operations of crude oil and product pipelines/terminals/berths/tank farms operating in western U.S., including regulatory compliance, emergency and spill response, and telecommunications and SCADA organizations supporting operations.

Position: Vice President and Manager of Operations
Duties:

- > Full operational responsibility
- > Major ship berth operations
- > New acquisitions
- > Several thousand miles of common carrier and private pipelines

Arco Product CQC Kiln

1985

Operations manager of new plant acquisition, including major cogeneration power generation, with full profit center responsibility.

Position: Plant Manager
Duties:

- > Team building of new facility that had been failing
- > Plant design modifications and troubleshooting
- > Setting expense and capital budgets, including key gas supply negotiations
- > Modification of steam plant, power generation, and environmental controls

Arco Products Co.

1981 - 1985

Operated Refined Product Blending, Storage and Handling Tank Farms, as well as Utility and Waste Water Treatment Operations for the third largest refinery on the west coast.

Position: Operations Manager of Process Services
Duties:

- > Modernize refinery utilities and storage/blending operations
- > Develop hydrocarbon product blends, including RFGs
- > Modification of steam plants, power generation, and environmental controls
- > Coordinate new major cogeneration installation, 400 MW plus

Arco Products Co.

1977 - 1981

Coordinated short and long-range operational and capital planning, and major expansion for two west coast refineries.

Position: Manager of Refinery Planning and Evaluation
Duties:

- > Establish monthly refinery volumetric plans
- > Develop 5-year refinery long range plans
- > Perform economic analysis for refinery enhancements
- > Issue authorization for capital/expense major expenditures

Arco Products Co.

1973 - 1977

Operating Supervisor and Process Engineer for various major refinery complexes.

Position: Operations Supervisor/Process Engineer
Duties:

- > FCC Complex Supervisor
- > Hydrocracker Complex Supervisor
- > Process engineer throughout major integrated refinery improving process yield and energy efficiency

Qualifications:

Served for over fifteen years as a member representing the public on the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise PHMSA on pipeline safety regulations.

Committee members are appointed by the Secretary of Transportation.

Served seven years, including position as its chairman, on the Washington State Citizens Committee on Pipeline Safety (CCOPS).

Positions are appointed by the governor of the state to advise federal, state, and local governments on regulatory matters related to pipeline safety, routing, construction, operation and maintenance.

Served on Executive subcommittee advising Congress and PHMSA on a report that culminated in new federal rules concerning Distribution Integrity Management Program (DIMP) gas distribution pipeline safety regulations.

As a representative of the public, advised the Office of Pipeline Safety on proposed new liquid and gas transmission pipeline integrity management rulemaking following the pipeline tragedies in Bellingham, Washington (1999) and Carlsbad, New Mexico (2000).

Member of Control Room Management committee assisting PHMSA on development of pipeline safety Control Room Management (CRM) regulations.

Certified and experienced HAZOP Team Leader associated with process safety management and application.

Education:

MBA (1976)
BS Chemical Engineering (1973)
BS Chemistry (1973)

Pepperdine University, Los Angeles, CA
University of California, Davis, CA
University of California, Davis, CA

Publications in the Public Domain:

1. "An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington," prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.
2. "Preventing Pipeline Failures," prepared for the State of Washington Joint Legislative Audit and Review Committee ("JLARC"), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.
3. "Pipelines - National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.
4. "Preventing Pipeline Releases," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.
5. "Pipeline Integrity and Direct Assessment, A Layman's Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.
6. "Public Safety and FERC's LNG Spin, What Citizens Aren't Being Told," jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.
7. "A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.
8. "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.
9. "The Proposed Corrib Onshore System - An Independent Analysis," prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.
10. "Observations on Sakhalin II Transmission Pipelines," prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.
11. "Increasing MAOP on U.S. Gas Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.
12. "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick," prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.
13. "Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB," by Richard B. Kuprewicz, dated October 18, 2006.
14. "General Observations On the Myth of a Best International Pipeline Standard," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.
15. "Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.
16. "Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer," prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.
17. "Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.
18. "Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt. Redoubt Volcano threat to the Drift River Oil Terminal," prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. "Observations on the Keystone XL Oil Pipeline DEIS," prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.
20. "PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline," prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.
21. "The State of Natural Gas Pipelines in Fort Worth," prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.
22. "Accufacts' Independent Observations on the Chevron No. 2 Crude Oil Pipeline," prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.
23. "Accufacts' Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline," prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.
24. "Accufacts' Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ," prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.
25. "Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E's Pipeline Safety Enhancement Plan," submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.
26. "Evaluation of the Valve Automation Component of PG&E's Safety Enhancement Plan," extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.
27. "Accufacts' Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project," prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.
28. "Accufacts' Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ," prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.
29. "Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming," prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.
30. "Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery," prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.
31. "Analysis of SWG's Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005," prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.
32. "Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria," prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.
33. "Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas," prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.
34. "Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000," prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.
35. "Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline's Northeast Upgrade Project," prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. "Report on Pipeline Safety for Enbridge's Line 9B Application to NEB," prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.
37. "Accufacts' Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria," prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.
38. "Accufacts' Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing," prepared by Richard B. Kuprewicz, November 25, 2013.
39. "Accufacts Inc. Evaluation of Transco's 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.
40. Accufacts report "DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks," prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.
41. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.
42. Accufacts' "Evaluation of Actual Velocity Critical Issues Related to Transco's Leidy Expansion Project," prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.
43. "Accufacts' Report to Portland Water District on the Portland – Montreal Pipeline," with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 2014.
44. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.
45. Review of Algonquin Gas Transmission LLC's Algonquin Incremental Market ("AIM Project"), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d," prepared by Richard B. Kuprewicz, and dated Nov. 3, 2014.
46. Accufacts' Key Observations dated January 6, 2015 on Spectra's Recent Responses to FERC Staff's Data Request on the Algonquin Gas Transmission Proposal (aka "AIM Project"), FERC Docket No. CP 14-96-000) related to Accufacts' Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.
47. Accufacts' Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.
48. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing on the Proposed System Integrity Projects ("SIP") to the Mississippi Public Service Commission ("MPSC") under Docket No. 15-UN-049 ("Docket"), prepared by Richard B. Kuprewicz, dated June 12, 2015.
49. Accufacts' Report to the Shwx'owhamel First Nations and the Peters Band ("First Nations") on the Trans Mountain Expansion Project ("TMEP") filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.
50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ ("Township"), to the Township of Chesterfield, NJ, dated February 18, 2016.
51. Accufacts Report, "Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7," dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).
52. Accufacts Report, "A Review, Analysis and Comments on Engineering Critical Assessments as proposed in

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.
54. Accufacts Report, "Accufacts Review of the U.S. Army Corps of Engineers (USACE) Environmental Assessment (EA) for the Dakota Access Pipeline ("DAPL")," prepared for Earthjustice by Richard B. Kuprewicz, dated October 28, 2016.
55. Accufacts' Report on Mariner East 2 Expansion Project Affecting West Goshen Township, dated January 6, 2017, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.
56. Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle, for the City of Newcastle, WA, June 20, 2017.
57. Accufacts Review of the Draft Environmental Impact Statement for the Line 3 Pipeline Project Prepared for the Minnesota Department of Commerce, July 9, 2017, filed on behalf of Friends of the Headwaters, to Minnesota State Department of Commerce for Docket Nos. CN-14-916 & PPL-15-137.
58. Testimony of Richard B. Kuprewicz, president of Accufacts Inc., in the matter West Goshen Township and Concerned Citizens of West Goshen Township v. Sunoco Pipelines, L.P. before the Pennsylvania Public Utilities Commission, Docket No. C-2017-2589346, on July 18, 2017, on Behalf of West Goshen Township and Concerned Citizens of West Goshen Township.
59. Direct Testimony of Richard B. Kuprewicz, president of Accufacts Inc., on Behalf of Friends of the Headwaters regarding Enbridge Energy, Limited Partnership proposal to replace and reroute an existing Line 3 to the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (MPUC PL-9/CN-14-916 and MPUC PL-9/PPL-15-137), September 11, 2017 and October 23, 2017.
60. Direct Testimony of Richard B. Kuprewicz On Behalf of The District of Columbia Government, before the Public Service Commission of the District of Columbia, in the matter of the merger of AltaGas Ltd. and WGL Holdings, Inc., Formal Case No. 1142, September 29, 2017.
61. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2018 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated December 4, 2017.
62. Report to Hugh A. Donaghue, Esquire, Concord Township Solicitor, "Accufacts Comments on Adelphia Project Application to FERC (Docket No. CP18-46-000) as it might impact Concord Township," dated May 30, 2018.
63. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2019 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 20, 2018.
64. Report to West Goshen Township Manager, PA, "Accufacts report on the repurposing of an existing 12-inch Sunoco pipeline segment to interconnect with the Mariner East 2 and Mariner East 2X crossing West Goshen Township," dated November 8, 2018.
65. Report to West Whiteland Township Manager, PA, "Accufacts Observations on Possible Pennsylvania State Pipeline Safety Regulations," prepared by Richard B. Kuprewicz, dated March 22, 2019.
66. Accufacts Public Comments on the Proposed Joint Settlement, BI&E v. Sunoco Pipeline L.P. ("SPLP"), Docket No. C-2018-3006534 ("Proposed Settlement"), submitted on August 15, 2019 to the Pennsylvania Public Utility Commission on the behalf of West Goshen Township as an intervener.
67. Report to West Whiteland Township Manager, Ms. Mimi Gleason, "Accufacts Perspective on Two Questions from West Whiteland's Board of Supervisors on Proposed Changes to ME 2 and ME 2X Construction/Operational Activities within West Whiteland," dated September 5, 2019."

68. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the episode on the evening of 8-5-19 at the Mariner East Boot Road Pump Station ("Event"), Boot Road, West Goshen Township, PA," dated September 16, 2019. BMC-51 (RBK-3)
February 3, 2023
Page 8 of 8
69. Provided direct testimony before the Arizona Corporation Commission, In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on Fair Value of the Properties of Southwest Gas Corporation Devoted to its Arizona Operations (Docket No. G-01551A-19-0055), testified on behalf of Utilities Division Arizona Corporation Commission, February 19, 2020.
70. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the Mariner East 2X Pipeline Affecting West Goshen Township," dated July 23, 2020.
71. Assisted the Commonwealth of Massachusetts, Office of the Attorney General in developing pipeline safety processes to be incorporated into the settlement agreement related to Columbia Gas' sale of Assets to Eversource following the Merrimack Valley, Massachusetts overpressure event of September 13, 2018.
72. Report to Natural Resources Defense Council, Inc., "Accufacts' Observations on the Use of Keystone XL Pipeline Pipe Exhibiting External Coating Deterioration Issues from Long Term Storage Exposure to the Elements," October 1, 2020.
73. Report to Pennsylvania Public Utilities Commission ("PAPUC"), "Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations," dated October 29, 2021, prepared for West Whiteland Township Board of Supervisors, West Whiteland Township, PA. Filed to PAPUC public web docket November 5, 2021 by West Whiteland Township under Reference Docket Number L-2019-3010267. Addresses suggested improvements in proposed pipeline safety rules for PA intrastate liquid transmission pipelines.
74. Submitted written testimony of Richard B. Kuprewicz on Behalf of Bay Mills Indian Community to ALJ Dennis Mack, dated December 14, 2021, in the matter of the Application of Enbridge Energy, Limited Partnership for Authority to Replace and Relocate the Segment of Line 5 Crossing the Straits of Mackinac into a Tunnel Beneath the Straits of Mackinac, before the State of Michigan Public Service Commission, U-20763.
75. Public presentation to New York State Indian Point Nuclear Facility Decommissioning Oversight Board on Holtec removal activities in proximity to Enbridge three Natural Gas Transmission Pipelines, March 17, 2022.
76. Report to Pipeline Safety Trust and Bold Alliance, "Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.," March 23, 2022.
77. Accufacts Inc., Public Presentation For the National Academies of Science Engineering Medicine and The Transportation Research Board, "To Committee on Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines," 4/27/22.
78. Accufacts Inc, "6/13/22 Webinar to Illinois Emergency Responders, Healthcare Providers, & Local Officials on Responses to CO₂ Transmission Pipeline Releases," 6/13/22.
79. Accufacts Report for Pipeline Safety Trust, "Safety of Hydrogen Transportation by Gas Pipelines," 11/28/22.

EXHIBIT BMC-52



CONTRACT / AGREEMENT

Testimony of Richard D. Kuprewicz

Number
(Assigned by **FINANCE**)

1999
BMC-52 (RBK-4)
February 03, 2003
Page 1 of 28

| | |
|---|--|
| <p>Originating Department: <i>Executive</i></p> <p>Contract With: <i>Olympic Pipe Line Co.</i></p> <p>Contract Name/Project #: <i>Memo. of understanding</i></p> <p>Termination Date: <i>3</i></p> | <p>Modification of Contract #: (Attach Copy of Original Contract)</p> <p>Contract Name/Project #:</p> <p>If Contract is Extended, New Termination Date:</p> |
| <p><input checked="" type="checkbox"/> Certificate of Insurance Attached <i>N/A</i></p> <p>Signatures:</p> <p><input checked="" type="checkbox"/> Contracting Party</p> <p><input checked="" type="checkbox"/> Department Head</p> <p>Date Executed <i>9/10/99</i></p> <p><input type="checkbox"/> Property Index Form</p> <p><input type="checkbox"/> Record Document</p> | <p>SPECIAL INSTRUCTIONS: <i>9/10/99 Notes/Cris/JSS-SCAN</i></p> |

Distribution **Original:** Attach to Contract **Copy:** Return to Originating Department

MASTER AGREEMENT

WHEREAS, the parties to this Master Agreement are the City of Bellingham (hereinafter "City") and Olympic Pipe Line Company (hereinafter "Olympic"); and,

WHEREAS, Olympic operates a petroleum pipeline (hereinafter "Pipeline") within the City; and,

WHEREAS, the parties acknowledge that the terms of the Franchise Agreement dated May 4, 1964 (the "1964 Franchise") are still in effect; and,

WHEREAS, the City will grant an interim license to Olympic to construct, repair, test, operate and maintain the Pipeline through land owned by the City in Whatcom Falls Park concurrently with the execution of this Master Agreement; and,

WHEREAS, the City and Olympic will execute a new interim franchise agreement to govern Olympic's Pipeline in the City's rights of way and streets under the same terms and conditions as the parties' License Agreement governing Whatcom Falls Park; and,

WHEREAS, the parties will work in good faith to develop long-term agreements to govern the entire portion of Olympic's Pipeline in the City (if a by-pass route around Bellingham is not feasible); and

WHEREAS, Olympic intends to develop a plan which addresses long-range safety and environmental issues, and public awareness and education for those communities through which the pipeline passes;

NOW, THEREFORE, in consideration of the mutual covenants contained herein, the parties agree as follows:

1. Concurrently with the execution of this Master Agreement the City will grant a license to Olympic to construct, repair, test, operate and maintain a petroleum pipeline through land owned by the City in Whatcom Falls Park. Said License Agreement is in the form attached hereto, is incorporated herein by reference and provides the terms and conditions for Olympic to construct, test, operate, maintain, repair, replace, remove and, potentially, abandon the pipeline on City property in Whatcom Falls Park.

2. The parties acknowledge that the terms of the 1964 Franchise were and are still in effect for Olympic's Pipeline in the City's land. Upon execution thereof, the License Agreement will supplement the terms of the 1964 Franchise as to City property in Whatcom Falls Park.

3. The parties agree that the terms and conditions outlined in the License Agreement

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governing Whatcom Falls Park shall be the terms of the new interim franchise agreement, contingent upon City Council's approval, for Olympic's Pipeline in City rights of way and public streets. Upon adoption thereof, said new interim franchise agreement will supplement the terms the terms of the 1964 Franchise Agreement. Until the adoption of said new interim franchise agreement under this paragraph, the parties agree that the indemnity and insurance provisions contained in the License Agreement shall supplement the terms of the 1964 Franchise. The new indemnity and insurance provisions shall apply to claims arising from occurrences on or after the date this Master Agreement is executed until a new agreement or agreements are enacted governing the entire Pipeline in the City. The 1964 Franchise shall terminate on May 4, 2000 unless on an earlier date pursuant to the termination provisions of this Agreement.

4. The parties will work in good faith to develop long-term agreements to govern the entire portion of Olympic's Pipeline in the City (if a by-pass route around Bellingham is not feasible).

5. Olympic shall pay to the City the amount of One Hundred ~~Fifteen~~ ^{Twenty Five} Thousand UNITED STATES DOLLARS (\$ ~~150,000~~ ^{250,000}) at the time this Master Agreement is executed and an additional ~~Seventy Five~~ ^{Twenty Five} Thousand UNITED STATES DOLLARS (\$ ~~75,000~~ ^{25,000}) on or before the date of execution of a long-term Franchise Agreement. The City shall use said payment to pay the City's expenses incurred in evaluating Olympic's proposals and studies and for entering into, monitoring and implementing the performance of this Agreement.

6. Olympic may proceed with repairs to the Pipeline and hydrostatic testing upon execution of this Master Agreement and the License referenced herein. Olympic agrees to comply with all directives of the United States Department of Transportation order(s), including, but not limited to, the original conditions of the June 18, 1999, order and any amendments thereto. In addition, Olympic will implement the "Pipeline Safety Immediate Action Plan" as outlined in the attached document, which is incorporated herein by this reference. If Olympic fails to comply with these conditions, or other terms of this Agreement, the License Agreement, the 1964 Franchise, or the new franchise agreement governing the pipeline in City rights of way and public streets if enacted by City Council, the City may terminate this Agreement, the License Agreement, the 1964 Franchise and the new interim franchise, in accordance with the procedure contained in the License Agreement. Resumption of service is dependent upon approval of the United States Department of Transportation

7. Olympic agrees to commission and complete a study, to be performed by a qualified, impartial, third party who is acceptable to both parties, to determine the feasibility of future rerouting of the pipeline outside the City. This study shall be completed not later than February 1, 2000 and shall be provided to both parties upon completion. Prior to May 4, 2000, the parties will undertake good faith negotiations regarding implementing any measures that the study and both parties deem reasonably feasible.

8. Olympic acknowledges that the rights granted pursuant to this Master Agreement,
Master Agreement - 2

License, the 1964 Franchise and the new interim franchise for use of City rights of way and public streets referenced herein are temporary in nature, that the City will seek additional terms and conditions for any renewal of a franchise agreement which it may grant to Olympic, and that by entering into this agreement the City is not obligated to grant to Olympic a franchise on terms requested by Olympic or otherwise. The City acknowledges that by entering into this Master Agreement, the License and the Franchise for use of City rights of way and public streets referenced herein, Olympic is not waiving any rights it claims to have to locate and operate its pipeline within the City nor its position that the federal government has preempted regulating interstate fuel pipelines. Olympic proceeds solely at its own risk in the construction, testing, maintenance, replacement and/or repair of the pipeline. Notwithstanding the reservation of rights contained in this paragraph, the parties agree to abide by the terms of this Agreement and the License referenced herein.

9. Upon filing any report with the Office of Pipeline Safety, the Washington Utilities and Transportation Commission, or any other federal or state regulatory agency regarding that portion of the Pipeline running in the City, Olympic shall simultaneously provide a copy of the report to the City. Olympic will provide the City with reports of safety related conditions as described in 49 CFR 195.56, even if filing of the reports with the Office of Pipeline Safety is excused pursuant to 49 CFR 195.55(b)(1) or (3).

10. It is the intent of the parties that this Agreement (and incorporated License) and the 1964 Franchise be treated as consistent, to the extent possible. If an inconsistency is encountered where the agreements cannot be harmonized, the provisions of this Agreement (and incorporated License) shall apply.

11. Waiver of any breach or condition of this Agreement shall not be deemed a waiver of any prior or subsequent breach or condition. No terms or conditions of this Agreement shall be held to be waived, modified or deleted except by a written instrument signed by authorized representatives of the parties.

12. Olympic shall not assign this Agreement without the City's consent, which consent shall not be unreasonably withheld.

13. This Agreement, including all attachments hereto and agreements contemplated herein including the 1964 Franchise, constitutes the entire agreement and understanding between the parties as to the subject matter of this Agreement. The Agreement may not be amended, modified, or supplemented except by a written instrument signed by authorized representatives of the parties.

14. This Agreement is for the benefit of the parties and not for any other person or third party beneficiary. Therefore, this Agreement's provisions shall not impart rights enforceable by any person, firm or organization other than a party to this Agreement.

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15. Any notice required to be given under the terms of this Agreement shall be directed to the party at the address set forth below:

City: City of Bellingham, 210 Lottie Street, Bellingham, WA 98225
Attn: Public Works Director

Olympic: Olympic Pipe Line Co., P.O. Box 1800, 2319 Lind Ave. S.W., Renton,
WA 98057
Attn: Frank Hopf

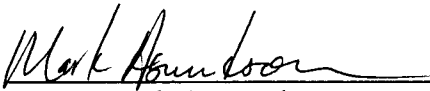
ACCEPTED AND ENTERED INTO THIS 10 DAY OF SEPTEMBER, 1999.


OLYMPIC PIPE LINE COMPANY


By: FRED CHOIGNACE
Title: PRESIDENT

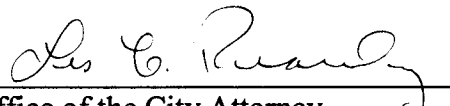
ACCEPTED AND ENTERED INTO THIS 10th DAY OF September, 1999.

CITY OF BELLINGHAM

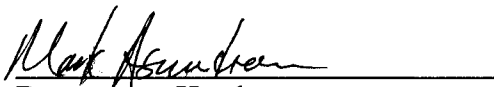

Mayor Mark Asmundson

Attest: 
Finance Director

Approved as to Form:


Office of the City Attorney

Departmental Approval:


Department Head

Master Agreement - 4

LICENSE FOR PETROLEUM PIPELINE

THIS AGREEMENT is freely made and entered into between the City of Bellingham (herein "Grantor") and Olympic Pipe Line Company (hereinafter "Grantee").

In consideration of ONE THOUSAND UNITED STATES DOLLARS (\$1000.00) and for other good and valuable consideration, which amount includes compensation for the temporary right set forth herein, and in consideration of the Grantee's performance of the covenants, terms and conditions hereinafter set forth, Grantor hereby conveys and grants to Grantee the following:

A non-exclusive temporary license across, in, through, upon and under Grantor's property as described in Exhibit A, which is attached hereto and expressly incorporated herein by this reference, for the purpose of installing, constructing, testing, operating, maintaining, repairing, replacing and using a petroleum pipeline (hereinafter "Pipeline"), together with a non-exclusive temporary reasonable right of ingress and egress from said easement for the foregoing purposes and for the period of the duration described herein.

The foregoing is granted subject to and conditioned upon the following terms, conditions, and covenants, which the parties hereby promise to faithfully and fully observe and perform:

1. Costs of Construction and Maintenance. Grantee shall be responsible for and promptly pay all costs and expenses of construction and maintenance of the Pipeline. Grantee agrees to hold Grantor harmless and defend Grantor from any and all liens arising directly or indirectly from any work performed, materials ordered or other obligations incurred by Grantee.
2. Specifications. Grantee shall construct the Pipeline in accordance with United States Department of Transportation requirements, the Pipeline Safety Immediate Action Plan, industry standards and federal and state regulations, which are expressly incorporated herein by reference.

LICENSE FOR PETROLEUM PIPELINE - 1

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3. Compliance with Laws and Regulations. Grantee shall at all times comply with all applicable federal, state and local statutes, codes, ordinances and all federal and state administrative orders, rules and regulations, as they may from time to time be amended, of any public authority having jurisdiction over Grantee and/or the Pipeline.
4. Review of Plans. Prior to any alteration, integrity testing, repair, replacement or removal of the Pipeline or any other substantial activity by Grantee on Grantor's property, Grantee shall provide written notification and plans and specifications for said work to Grantor for review. Grantee shall not commence any such work without Grantor's prior review of the plans by Grantor's Public Works Department for consistency with this Agreement, provided that in the event of an emergency requiring immediate action by Grantee for the protection of the Pipeline, Grantor's property or other persons or property, Grantee may take such action upon such notice to Grantor as is reasonable under the circumstances. Nothing in this Agreement shall be deemed to impose any duty or obligation on Grantor to determine the adequacy or sufficiency of Grantee's plans and designs or to ascertain whether Grantee's construction, testing, maintenance, repairs, replacement or removal is in conformance with the plans and specifications reviewed by Grantor.
5. As-Built Survey. Within thirty (30) days of completing any alteration, repair, replacement or removal of the Pipeline or any other substantial activity on Grantor's property, Grantee shall provide Grantor with as-built drawings (and a survey, if appropriate) showing that the location, depth and other characteristics of the Pipeline

conforms to the parties' plans and are consistent with the Master Agreement and this License.

6. Coordination of Activities. Grantee shall coordinate the dates of any alteration, repair, replacement or removal or other substantial activity by Grantee on Grantor's property with Grantor's Public Works Department, or such other Grantor employee as Grantor may periodically designate. Grantee shall provide Grantor with at least three (3) days' prior written notice of its intent to enter Grantor's property to commence said activity; provided that in the event of an emergency requiring immediate action by Grantee for the protection of the Pipeline, Grantor's property or other persons or property, Grantee may take such action upon such notice to Grantor as is reasonable under the circumstances.
7. Work Standards. All work to be performed by Grantee on Grantor's property shall be in accordance with the plans as submitted to Grantor and shall be completed in a careful and workmanlike manner, free from all claims or liens. Upon completion of the Pipeline's construction on Grantor's property, and upon completion of any and all subsequent work by Grantee on Grantor's property, Grantee shall remove all debris and restore the surface of Grantor's property as nearly as possible to the condition in which it was at the commencement of such work, and shall replace any property corner monuments, survey references, or hubs which were disturbed or destroyed during Grantee's work on Grantor's property.
8. Grantor's Access. Grantee shall ensure Grantor has continued access to the licensed area during periods in which Grantee is conducting construction or other activities on

Grantor's property. Grantor covenants that it will not jeopardize job site safety in accessing the licensed area under this provision.

9. Grantee's Access. Notwithstanding that Grantee is granted the right of ingress and egress from the licensed property, Grantee shall not exercise its right of ingress and egress in such locations as may from time to time be reasonably designated by Grantor and Grantee's right of ingress and egress shall be exercised pursuant to such reasonable rules and regulations as Grantor may specify. Grantor shall at all times have the right to erect fences on, over and/or across the licensed area or any part thereof and to occupy the licensed area with Grantor's facilities and equipment, provided Grantor provides Grantee alternate access to the property, and that Grantor does not substantially interfere with Grantee's licensed use.
10. Grantor's Representatives. Grantor will appoint one or more representatives who will see that Grantee's work on Grantor's property does not unreasonably jeopardize Grantor's operations, facilities or use of Grantor's property. Grantee shall not conduct any work nor fill over any work unless it has given Grantor at least one (1) business day notice to allow Grantor's representatives to be present at Grantee's work, except in the event of an emergency requiring Grantee's immediate action, in which case Grantee shall notify Grantor as soon as possible. Grantee and Grantee's contractors, subcontractors or agents shall promptly and fully comply with all reasonable orders and directions of Grantor's representatives, including, without limitation, cessation of work, and Grantee's contracts shall so provide. Nothing in this provision shall be deemed to impose or create any obligations or duties upon Grantor.

11. Grantee's Activities. Grantee shall exercise its rights hereunder so as to minimize, and avoid if reasonably possible, interference with Grantor's use of its property, including but not limited to the licensed area for park, water, sewer, utility or other municipal purposes. Grantee shall at all times conduct its activities on Grantor's property so as not to interfere with, obstruct or endanger Grantor's use of the property. Markers demarcating the location of the pipeline shall be placed on the surface so as to provide clear warning of the presence of the pipeline but in a manner that does not interfere with trails or other public uses in the area.

12. Grantor's Activities. Nothing contained herein shall prevent or preclude Grantor from undertaking construction, installation or use of the property as Grantor deems necessary, and which does not substantially interfere with Grantee's use, and Grantor shall not be liable to Grantee, or to Grantee's employees, agents, contractors, subcontractors and users of the Pipeline, for any loss or injury resulting from any damage or destruction of the Pipeline directly or indirectly caused by Grantor's use of the licensed area or Grantor's facilities on the licensed area. Upon notification to Grantee of construction by another within five (5) feet of Grantee's Pipeline, Grantee shall provide a representative to inspect the construction to see that Grantee's Pipeline is not damaged from the construction. The person or entity doing the construction shall comply with Grantee's representative's reasonable orders and directions in order to prevent damage to the pipeline.

13. Term. This Agreement shall expire on May 4, 2000, unless sooner terminated or modified as provided herein.

14. Termination.

14.1 Grantor may terminate this Agreement prior to May 4, 2000, upon the occurrence of any of the following events:

- A. If Grantee materially breaches or otherwise fails to perform, comply with or otherwise observe any of the terms and conditions of this Agreement, the Master Agreement or Safety Action Plan, or fails to maintain all required licenses and approvals from federal, state, and local jurisdictions, and fails to cure such breach or default within twenty (20) calendar days of Grantor's providing Grantee written notice thereof, or, if not reasonably capable of being cured within twenty (20) calendar days, within such other reasonable period of time as the parties may agree upon.
- B. The uncontained release of any petroleum product from the Pipeline totaling more than one barrel above ground or five barrels below ground within the City of Bellingham or if any such release of the Pipeline's petroleum product flows or migrates into the City of Bellingham, unless Grantee establishes that such release was not caused or contributed to in any way by the negligence or fault of the Grantee, its agents or contractors.
- C. This Agreement shall not be terminated except upon a majority vote of the City Council, after reasonable notice to Grantee and an opportunity to be heard, provided that if exigent circumstances necessitate immediate termination, the hearing may be held as soon as possible after the termination.

14.2 In the event of termination under section 14 of this Agreement, Grantee shall

immediately discontinue operation of the Pipeline through the licensed area, and Grantor

LICENSE FOR PETROLEUM PIPELINE - 6

City of Bellingham
CITY ATTORNEY
210 Lottie Street
Bellingham, Washington 98225
Telephone (360) 676-6903

may in such case declare a forfeiture of the license and enforce such forfeiture in the manner provided by law or this Agreement. In the event that Olympic's rights to the use of the licensed or franchised areas have definitively ceased, or if Olympic abandons the pipeline or any portion thereof, Olympic shall within 180 days after abandonment or cessation of the right to use the licensed or franchised areas, remove the pipeline or secure the pipeline in such a manner as to cause it to be as safe as is reasonably possible, by removing all liquid hydrocarbons, purging vapors, displacing the contents of the line with an appropriate inert material and sealing the pipe ends with a suitable end closure, in compliance with all applicable regulations and industry standards and providing for periodic monitoring of the abandoned line for as long as the pipe remains in the ground; provided that portions of the pipeline which are above ground shall be removed. In the event of the removal of all or a portion of the Pipeline, Grantee shall restore Grantor's property and the licensed or franchised area to a condition that existed prior to the installation of Grantee's facilities. Such property restoration work shall be done at Grantee's sole cost and expense and to Grantor's reasonable satisfaction. If Grantee is required to remove or secure the Pipeline and fails to do so and to restore the premises or take such other mutually agreed upon action, Grantor may, after reasonable notice to Grantee, remove the Pipeline, restore the premises or take such other action as is reasonably necessary at Grantee's expense and Grantor shall not be liable therefor.

14.3 Grantor's right to terminate this Agreement is in addition to and not in limitation of any other remedy of Grantor at law or equity. Grantor's failure to exercise such remedy at

any time shall not waive Grantor's right to terminate or assert any other remedy at law or equity for any future breach or default of Grantee.

14.4 Termination of this Agreement shall not release Grantee from any liability or obligation with respect to any matter occurring prior to such termination, nor shall such termination release Grantee from any obligation to remove the Pipeline from Grantor's property and restore the premises.

15. Non-exclusive Agreement. This license is non-exclusive. Grantor reserves all rights to its property, including, without limitation, the right to grant easements, licenses and permits to others subject to the rights granted in this Agreement, provided that Grantor shall not grant any other license, easement or permit which would substantially interfere with Grantee's use.

16. Indemnification.

16.1 General Indemnification. Grantee shall indemnify, defend and hold harmless Grantor from any and all liability, loss, damage, cost, expense, and claim whatsoever, whether at law or in equity, arising out of or related to, directly or indirectly, the construction, operation, use, location, testing, repair, maintenance, removal, abandonment or damage to Grantee's Pipeline, or from the existence of Grantee's Pipeline and other facilities, and of the products contained in, transferred through, released or escaped from said Pipeline and facilities, from any and all causes whatsoever, including, but not limited to, the sole or concurrent fault of the Grantor, Grantee or third parties. If any action or proceeding is brought against Grantor by reason of the Pipeline or its facilities, Grantee shall defend the Grantor at the Grantee's complete expense, provided that, for uninsured

actions or proceedings, defense attorneys shall be approved by Grantor which approval shall not be unreasonably withheld.

16.2 *Environmental Indemnification.* Grantee shall indemnify, defend and save Grantor harmless from and against any and all liability, loss, damage, expense, actions and claims, either at law or in equity, including, but not limited to, costs and reasonable attorneys' and experts' fees incurred by Grantor in defense thereof, arising directly or indirectly from (a) Grantee's breach of any environmental laws applicable to the Pipeline or (b) from any release of a hazardous substance on or from the Pipeline or (c) other activity related to this License by Grantee, its agents, contractors or subcontractors. This indemnity includes but is not limited to (a) liability for a governmental agency's costs of removal or remedial action for hazardous substances; (b) damages to natural resources caused by hazardous substances, including the reasonable costs of assessing such damages; (c) liability for any other person's costs of responding to hazardous substances; (d) liability for any costs of investigation, abatement, correction, cleanup, fines, penalties, or other damages arising under any environmental laws; and (e) liability for personal injury, property damage, or economic loss arising under any statutory or common-law theory.

16.3 *Definitions.*

A. "Hazardous Substance" means any hazardous, toxic, or dangerous substance, material, waste, pollutant, or contaminant, including all substances designated under the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et seq.; the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. § 9601 et seq.; the Hazardous Materials Transportation Act, 49 U.S.C. § 1801 et seq.; the Federal Water Pollution Control Act, 33 U.S.C. § 1257 et seq.; the Clean Air Act, 42 U.S.C. § 7401 et seq.; the Toxic Substances Control Act, 15 U.S.C. § 2601 et seq.; the Federal Insecticide, Fungicide, Rodenticide Act, 7 U.S.C. § 136 et seq.; the Washington

Hazardous Waste Management Act, Chapter 70.105 RCW; and the Washington Model Toxics Control Act, Chapter 70.105D RCW; all as amended from time to time; or any other federal, state, or local statute, code, or ordinance or lawful rule, regulation, order, decree, or other governmental authority as now or at any time hereafter in effect. The term shall specifically include petroleum and petroleum products. The term shall also be interpreted to include any substance which, after release into the environment, will or may reasonably be anticipated to cause death, disease, behavior abnormalities, cancer, or genetic abnormalities.

B. "Environmental Laws" shall include the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et seq.; the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. § 9601 et seq.; the Hazardous Materials Transportation Act, 49 U.S.C. § 1801 et seq.; the Federal Water Pollution Control Act, 33 U.S.C. § 1257 et seq.; the Clean Air Act, 42 U.S.C. § 7401 et seq.; the Toxic Substances Control Act, 15 U.S.C. § 2601 et seq.; the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. § 136 et seq.; the Occupational Safety and Health Act, 29 U.S.C. § 651 et seq.; the Washington Hazardous Waste Management Act, Chapter 70.105 RCW; and the Washington Model Toxics Control Act, Chapter 70.105D RCW; all as amended from time to time; or any other federal, state, or local statute, code, or ordinance or federal or state administrative rule, regulation, ordinance, order, decree, or other governmental authority as now or at any time hereafter in effect pertaining to the protection of human health or the environment.

17. Insurance. During this Agreement, Grantee shall provide and maintain, at its own cost, insurance in the minimum amount of FIFTY MILLION UNITED STATES DOLLARS (\$50,000,000.00) each occurrence, which shall be raised to at least ONE HUNDRED MILLION UNITED STATES DOLLARS (\$100,000,000.00) each occurrence not later than October 31, 1999, in a form and with a carrier reasonably acceptable to the Grantor, naming Grantor as an additional insured, to cover any and all insurable liability, damage, claims and loss as set forth in Section 16.1 above, and, to the extent such coverage is reasonably available in the commercial marketplace, all liability, damage, claims and loss as set forth in Section 16.2 above, except for liability for fines and penalties for violation of environmental laws and as otherwise provided below. Insurance coverage shall include, but is not limited to, all defense costs. Such insurance shall include, but is not limited to, pollution liability coverage at least as broad as the coverage currently in place under Olympic's existing policy, at a minimum covering liability from sudden and accidental occurrences, subject to time element reporting requirements, and such other applicable pollution coverage as is reasonably available in the commercial marketplace. Proof of insurance and a copy of the insurance policy, including, but not limited to, coverage terms and claims procedures, shall be provided to the Grantor prior to the beginning of any substantial work, testing or construction or reconstruction on the Pipeline. Said insurance shall contain a provision that it shall not be cancelled without a minimum of thirty days prior written notice to the Grantor. This indemnity and insurance provision shall survive the termination of this Agreement and shall continue for as long as the Grantee's facilities shall remain in or on the licensed area or until the parties execute a new license, easement

or franchise agreement which modifies or terminates these indemnity or insurance provisions.

18. Taxes. Grantee shall promptly pay any and all taxes, including those that may be levied as a result of this Agreement or relating to Grantee's Pipeline.

19. Assignment. Grantee shall not assign its rights hereunder without the consent of the City, which consent shall not be unreasonable withheld.

20. Feasibility Study. Grantee is undertaking to study the feasibility of relocating the Pipeline outside the City of Bellingham. Currently, Grantee will be constructing and operating the Pipeline in the existing route, which is denominated in Exhibit A. However, within one hundred and fifty (150) calendar days, or such other time the parties may mutually agree to, following the feasibility study's completion, and assuming that a franchise and license are in place between the parties with a term of ten (10) years or more, Grantee shall either relocate the Pipeline to the deep bore route, which is denominated as "Proposed Horizontal Drill" in Exhibit B, or relocate its pipeline outside the City of Bellingham within five years of the date of the study. Provided this paragraph shall not apply if Grantee is prohibited from relocating due to an order or directive from a governmental entity with jurisdiction over Grantee and the pipeline.

21. Modification. Any modification, change or alteration to this Agreement shall only be effective if completed in writing and executed by authorized representatives of each party.

22. Notice. Any notice required to be given under the terms of this Agreement shall be directed to the party at the address set forth below:

City: City of Bellingham, 210 Lottie Street, Bellingham, WA 98225

Attn: Public Works Director

Olympic: Olympic Pipe Line Co., P. O. Box 1800, 23 Lind Ave. S.W.

Renton, WA 98057

Attn: Frank Hopf

AGREED THIS 10 DAY OF SEPTEMBER, 1999 FOR OLYMPIC PIPE LINE COMPANY.

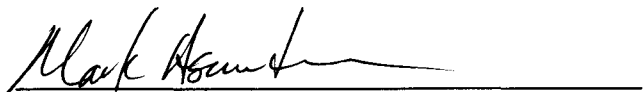
By:



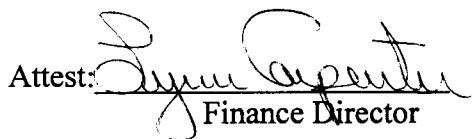
Title:

PRESIDENT

AGREED THIS 10th DAY OF SEPTEMBER, 1999 FOR CITY OF BELLINGHAM.


Mark Asmundson, Mayor

Attest:

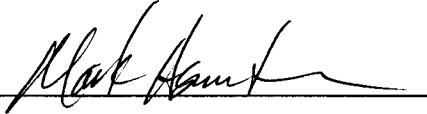

Finance Director

APPROVED AS TO FORM:


Office of the City Attorney

LICENSE FOR PETROLEUM PIPELINE - 13

DEPARTMENTAL APPROVAL:

A handwritten signature in black ink, appearing to read "Mark Hunt", is written over a horizontal line.

LICENSE FOR PETROLEUM PIPELINE - 14

s:\...er\olympic\license agreement6

City of Bellingham
CITY ATTORNEY
210 Lottie Street
Bellingham, Washington 98225
Telephone (360) 676-6903

EXHIBIT A

A strip of land 50 feet in width lying between the lines parallel to and situated 15 feet Easterly of and 35 feet Westerly of, measured at right angles, from the following described line:

Beginning at a point 35 feet East of a concrete monument set for the Center of Section 28, Township 38 North, Range 3 East of W.M., Whatcom County Washington:

Thence: South 00 degrees 52' West 57 feet to a point

Thence: South 17 degrees 11' West 732 feet to a point

Thence: North 72 degrees 49' West 160 feet to a point

Thence: South 17 degrees 11' West 200 feet to a point

Thence: South 10 degrees 32' East 353 feet to a point

Thence: South 17 degrees 11' West 421 feet to a point

Thence: South 15 degrees 11' West 100 feet to a point

Thence: South 2 degrees 02' West 438 feet to a point

in the North line of Lakeway Drive, said point being 480.70 feet North and 444.00 feet West of the quarter section corner of Sections 28 and 33 in Township 38 North, Range 3 East, being in all 2461 feet in length, more or less.

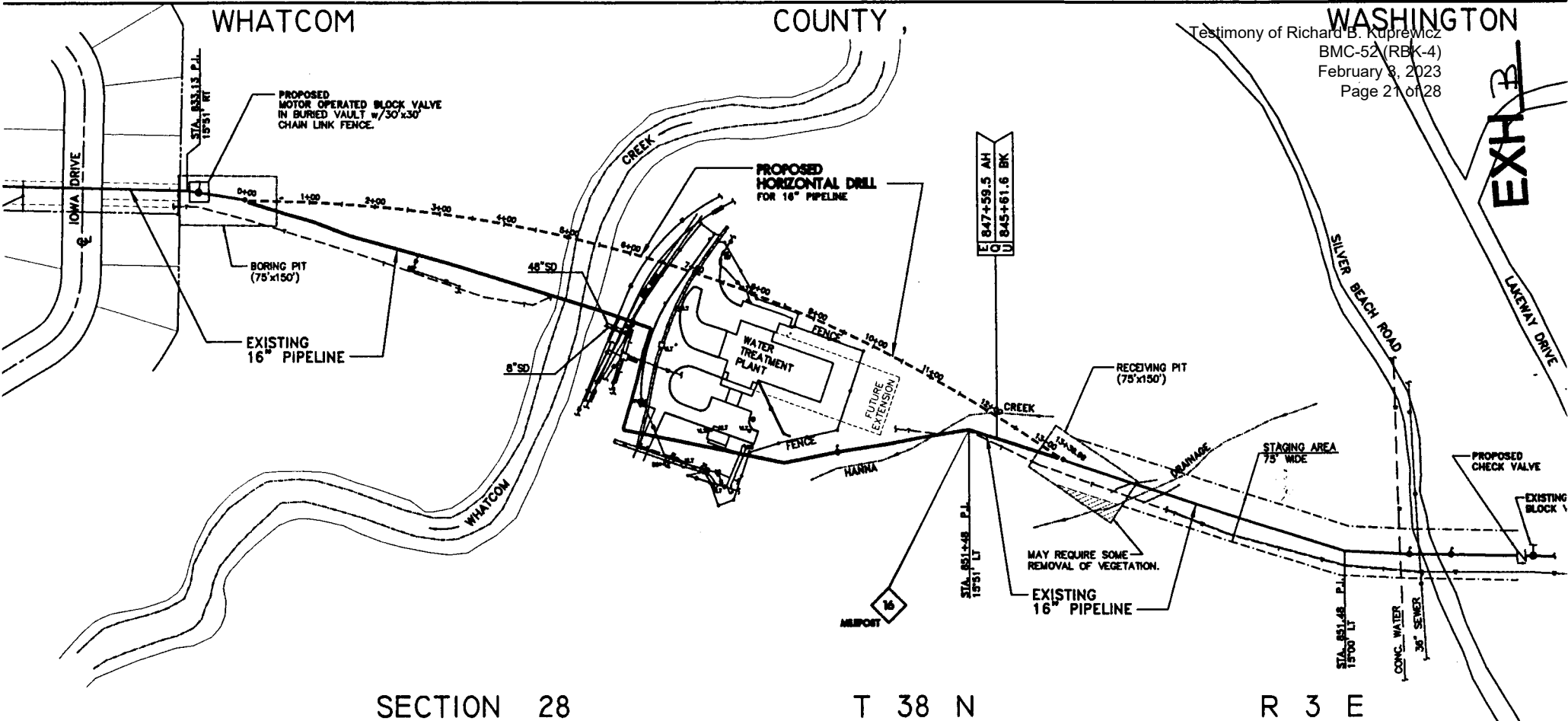
WHATCOM

COUNTY,

WASHINGTON

Testimony of Richard B. Kuprewicz
BMC-52 (RBK-4)
February 8, 2023
Page 21 of 28

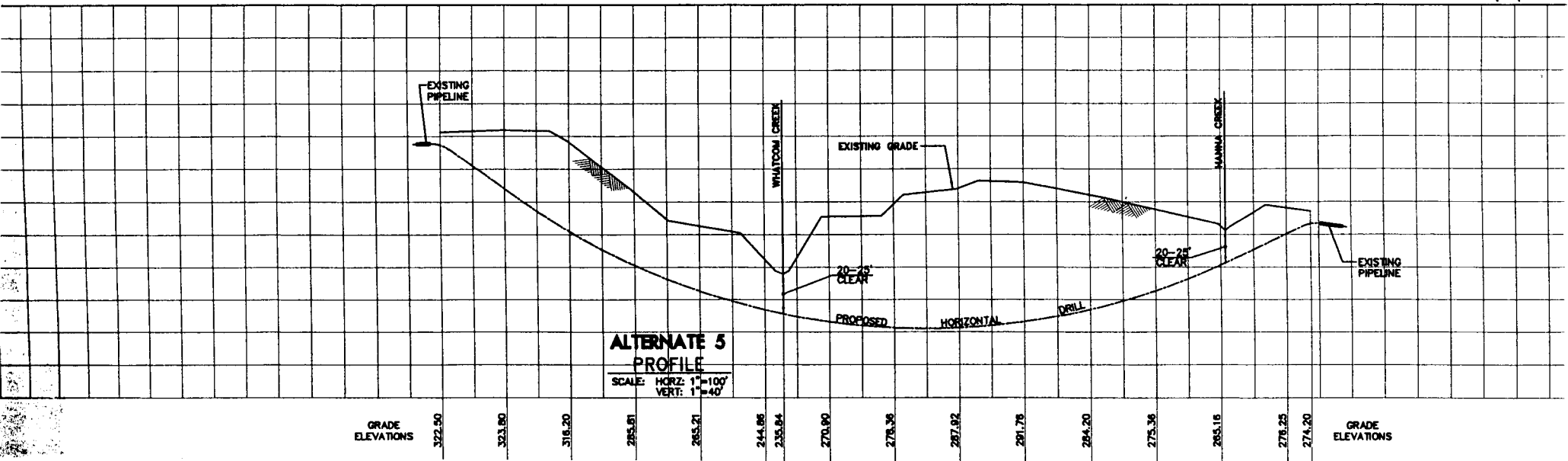
EXH B



SECTION 28

T 38 N

R 3 E



**ALTERNATE 5
PROFILE**
SCALE: HORIZ: 1"=100'
VERT: 1"=40'

| STATION | GRADE ELEVATIONS |
|---------|------------------|
| 0+00 | 322.90 |
| 1+00 | 323.80 |
| 2+00 | 316.20 |
| 3+00 | 295.61 |
| 4+00 | 285.21 |
| 5+00 | 244.86 |
| 6+00 | 235.84 |
| 7+00 | 270.80 |
| 8+00 | 276.36 |
| 9+00 | 287.82 |
| 10+00 | 291.76 |
| 11+00 | 284.20 |
| 12+00 | 275.36 |
| 13+00 | 285.16 |
| 14+00 | 276.25 |
| 15+00 | 274.20 |
| 16+00 | GRADE ELEVATIONS |

Pipeline Safety Immediate Action Plan

This Pipeline Safety Action Plan has been jointly developed by the City of Bellingham (“City”) and Olympic Pipe Line Company (“OPL”).

Definitions for the Olympic Pipe Line from Ferndale to Bayview:

- Specified Minimum Yield Strength (SMYS) of OPL's 16 inch diameter, 0.312 inch wall thickness API 5L X52 is 52,000psi.
- Maximum Operating Pressure (MOP) per 49 CFR part 195 is 1370 psig at Ferndale (equivalent to 68% SMYS). MOP varies along the line with elevation.
- Normal Operating Pressure (NOP) is 1320 psig at Ferndale discharge (equivalent to 65% SMYS). NOP varies along the line with elevation, distance, and product density.
- Operational restart means the initiation of petroleum product movements in the Ferndale to Bayview section of the pipeline.

I. General Terms Relating to Operational Restart and Operating Pressure

1.1. The pipeline between Ferndale and Bayview can not be operationally restarted until the following sections defined in the rest of this document have been completed:

- a) Hydrostatic test (section II)
- b) Surge Analysis (section III, except sections - 3.7, 3.9, and 3.10)
- c) SCADA Review (section IV, except 4.2)
- d) Mainline Valves (section VI, except sections 6.1 and 6.4)
- e) Leak Detection (section VII except section 7.2)
- f) Staffing and Training (section X)
- g) Additional Request from City (section XI)

OPL will prepare a detailed re-commissioning and startup plan for review by the City prior to operational restart. It will include staffing trained personnel at Ferndale and Bayview station during the first 12 hours of operation. The block valves at MP 7 and MP16 will also be manned during the first 12 hours of operation. OPL will ship only diesel and jet fuel during the first week of operation. The operating pressure at the Ferndale discharge will not exceed 70% of NOP at that location until the system operates properly as determined and documented by OPL to the City. Such documentation should include SCADA printouts that corroborate with results from the surge analysis defined in section 3.2.

1.2. After the system is operating properly at the 70% level, OPL may increase the operating pressure at Ferndale discharge to a maximum of 80% of the NOP at that location.

- 1.3. OPL may increase the operating pressure above 80% up to 100% MOP at Ferndale discharge when all of the following have been completed:
 - a) All injurious defects identified from the anomalies detected in the ultrasonic inline inspection have been repaired according to the procedures outlined in item 5.3 below.
 - b) The additional leak detection system described in section 7.2 is operational.
 - c) OPL notifies the City 24 hours in advance of its intent to increase pressure above 80% NOP. Such notice is to be sent to FAX No 360-738-7418.
- 1.4 Much of the regulation of interstate pipeline safety is under the sole jurisdiction of the United States Department of Transportation. Nothing in this plan shall be construed as an assertion by the City of such jurisdiction.

II. Hydrostatic Test

OBJECTIVE: Validate integrity of pipeline within the City

- 2.1. Replacement pipe to be installed near MP 16 will be 16 inch diameter, 0.500 inch wall thickness API 5L-X52 pipe. A concrete slab will be installed over the replacement pipe where future construction activities are expected as a warning barrier.
- 2.2. The hydrostatic test procedure will be reviewed with the City prior to commencement of the hydrostatic test.
- 2.3. OPL will subject the pipeline within the city limits (MP12 to MP22) to a minimum hydrostatic test pressure of 90% SMYS (equivalent to 1825 psig) for a minimum time period of 8 hours.
- 2.4. OPL will provide pressure – volume plot(s) to the City.
- 2.5. The hydrostatic test shall be conducted in accordance with API RP 1110 (hydrostatic test standards) and certified by a professional engineer.
- 2.6. During the hydrostatic test all failures will be investigated and repaired and their cause/analysis reported to the City.
- 1.7. Future MOP between MP12 and MP22 will be limited to 1370 psig at Ferndale discharge.
- 1.8. The City will sell OPL water for the hydrostatic test.



III. Surge Analysis

OBJECTIVE: Conduct a comprehensive analysis and prescribe an appropriate remedial plan to assure that maximum pressures are within 110% MOP within the City of Bellingham

- 3.1. OPL will provide a surge analysis reconstructing the June 10th events.
- 3.2. OPL and the City will agree on and simulate a "Base Case" representing normal operations with appropriate transient conditions. The "Base Case" will be used to determine whether the calculated pressure exceeds 110% MOP within the City. OPL will modify the operation and/or equipment if necessary to maintain pressure below 110% MOP. Cases of specified pressures at 70% and 80% NOP, and 100% MOP at Ferndale discharge will be simulated.
- 3.3. OPL and the City will agree on and simulate a "Worst Case" to determine if the calculated pressure exceeds 110% MOP within the City. OPL will modify its operation and/or equipment if necessary to keep "Worst Case" surges from exceeding 110% of MOP within the City.
- 3.4. Jim Liou (representing the City), Gerald Moreland of Stoner Associates (retained by OPL to conduct the surge analysis), and Ron Fischer (representing OPL) will determine the "Base Case" and the "Worst Case."
- 3.5. OPL will make sensitivity runs for cases where the calculated pressure within the City is "close" to 110% MOP. "Close" is defined as follows. Multiply the surge pressure rise by 1.2. Add the results to the pressure prior to the surge. If the sum exceeds 110% MOP, then sensitivity runs will be made.
- 3.6. OPL will allow a City representative to be present when simulation results of the June 10 incident are demonstrated to interested parties.
- 3.7. OPL will perform one successful field test to check the accuracy of the surge analysis. Jim Liou, Gerald Moreland, Ron Fischer, and Frank Hopf (representing OPL) will agree on the test details. The test will be performed within 45 days of increasing pressure above 80% NOP.
- 3.8. OPL will present the City, for its concurrence, the interim results of the surge analysis prior to operational restart.
- 3.9. OPL will provide the City with a detailed, written report on the surge analysis and field test results, including a report of remedial actions taken if any, within 45 days of completion of the field test.
- 3.10. The City's surge analyst expert will complete a review of the surge analyst report within two months of receiving it. If the City's surge expert identifies any concerns, OPL will

WJH
file

respond within 30 days.

IV. SCADA System

OBJECTIVE: Conduct a comprehensive review of SCADA to determine if the problem occurring prior to the accident has been corrected

4.1. OPL consultants have completed the following on the Renton SCADA system since June 10, 1999.

- Diagnostic analysis of system.
- Modification of system parameters.
- Failure analysis on software.
- Modification of hardware and software.

OPL will provide a final report on the SCADA analysis and modifications to the City on or about August 6, 1999.

4.2. The City's SCADA expert will complete a review of this report within two months after receiving the SCADA report. If the City's SCADA expert identifies any concerns, Olympic will respond within 30 days.

V. Internal Inspection of Pipeline from Ferndale to Bayview

OBJECTIVE: Assess the integrity of the complete pipeline from Ferndale to Bayview

5.1. OPL will run both a high-resolution magnetic flux inspection pig and an ultrasonic inspection pig. These tools represent the most advanced technologies for detecting metal loss in liquid pipelines. The several types of internal inspection tools provide different capabilities for detecting and characterizing the various types of pipeline defects.

5.2. OPL will also run a geometry inspection tool to inspect for out of round features.

5.3. After OPL receives results from each inspection tool run, it will prepare a list of anomalies and determine which require field inspection. This list will be provided to the City for its review and comments.

As the potentially injurious anomalies are inspected by OPL, the City will be invited to participate in the inspections. OPL will make all repairs in accordance with ASME B31.4 and ASME B31G. All injurious anomalies found by the Ultrasonic tool must be repaired before operating pressure can be increased above 80% NOP.

- 5.4. All inspection pig runs will be completed on the Ferndale to Bayview segment as soon as the pigs are available. It is expected that all of the above inspection pig runs will be completed within three months of operational restart and in any event no later than six months.

VI. Mainline Valves

OBJECTIVE: Reduce the size of spills

- 1.1. OPL will install a check valve at MP 8.1 (Silver Creek) and a remotely operated block valve near MP12 (near north city boundary). These valves will be installed as soon as permits are received from the county.
- 6.2. OPL will install a check valve at MP 16.22 (Lakeway Drive).
- 6.3. OPL will test all mainline valves from Ferndale to Bayview. OPL will test the remotely operated valves at MP7 and MP16.22 for remote operation and for ability to hold differential pressure. The tests will include observing movement of the valve, confirmation of command from the control center, and verification of the valves ability to hold a differential pressure. The results of the valve tests will be provided to the City for review prior to operational startup.
- 6.4. An independent consultant will perform a valve analysis. This assessment will consider the pipeline's elevation profile, its proximity to lakes, streams, wetlands, and other environmentally sensitive locations, including population centers, and economic areas. The analysis will: a) evaluate maximum spill volume (not limited to gravity drain), b) evaluate the likelihood of heavier than air vapor generation and its dispersion given the terrain and prevailing winds, c) determine if additional remote valves and check valves are necessary to mitigate potential hazards associated with a pipeline spill, d) recommend which block valves require remote operation, and e) identify critical valves which require a secondary method of remotely closing the valve independent of SCADA.

The report of the analysis affecting the City will be submitted to the City for its concurrence no later than October 31, 1999. OPL shall apply for any necessary permits within 21 days of receiving the City's concurrence. The City will expeditiously process applications for any permits for any valves within the City's jurisdiction. OPL will take any corrective action recommended by the report affecting the City by the later of May 4, 2000 or 90 days after issuance of required permits.

VII. Leak Detection

OBJECTIVE: Provide improved leak detection capability

- 7.1. The existing OPL SCADA system performs some leak detection functions. It also feeds real-time data to a dynamic hydraulic modeling system designed to detect leaks down to

the 1% of flow range. The reliability of the existing pipeline leak detection system has been enhanced by the SCADA improvements outlined in Section IV. OPL agrees that it will not operate the pipeline in slack line conditions.

- 7.2. OPL will install an additional leak detection system to detect major leaks. This system will be independent of SCADA and associated communication links. The flow meters at Ferndale and Bayview will be used to provide inflow - outflow comparison. The threshold for leak alarm will be set sufficiently high to eliminate false alarms due to line pack changes. OPL will notify the City of the threshold when it is established. After the threshold has been established by OPL, any alarm from this major leak detection system must result in immediate shutdown of the pipeline.

VIII. Management Audit

OBJECTIVE: Provide management oversight for pipeline safety issues

- 8.1. Within 180 days of operational restart, OPL will fund an independent safety audit conducted by third party pipeline consultant(s). These consultants will be selected jointly by OPL and the City. The purpose of this audit is to determine if there are adequate management processes in place to ensure that the pipeline is designed, maintained, and operated safely using the 14 elements within 29 CFR1910.119 as a guideline for the audit. The audit will be completed within 360 days of the hiring of the consultants.
- 8.2. The DOT Office of Pipeline Safety and the Washington Utilities and Transportation Commission will be invited to participate in the audit.
- 8.3. A copy of the safety audit report will be provided to the City by the consultants upon its delivery to OPL.
- 8.4. Within 45 days of the audit report, OPL will prepare a plan and schedule, satisfactory to the independent consultants, to resolve all deficiencies identified by the audit.
- 8.5. OPL will provide quarterly reports to the independent consultants and City until such time as all corrective actions are completed.

IX. Review of cathodic protection

OBJECTIVE: Assure Corrosion Control

- 9.1 OPL conducted a close interval survey on June 12 around the water treatment plant and no cathodic protection problems were detected. OPL annually checks cathodic protection systems in accordance with U.S. DOT regulations. OPL will review the results of the hydrostatic testing and inline inspections, and make any necessary cathodic protection improvements to address corrosion concerns identified by the hydrostatic testing and inline inspections.

*MA
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X. Staffing and Training

OBJECTIVE: Provide a Safe Operational Restart

- 10.1. OPL will have two experienced controllers on duty in the Control Center at all times.
- 1.2. OPL will not have any controller on duty with less than ten years experience during startup.
- 1.3. OPL will provide documentation that insures that all personnel are familiar with all changes implemented prior to operational restart.

XI. Additional Request from City

11.1. Failsafe Protection and Information Requirements.

To insure that the pipeline can be operated failsafe with regard to over pressure (no pressure surges in excess of 110% MOP), the maximum flow rate may need to be physically restricted. When necessary, this is to be accomplished by trimming the Ferndale mainline shipping pump impeller(s). The surge analysis completed in sections 3.2, 3.3, and 3.8, that has received the concurrence of the City, is to be used to set the maximum flow rate through impeller trimming (of the Ferndale to Bayview system). The future usage of bigger impellers and hence higher flow rates will only be permitted when OPL demonstrates to the City that under normal and upset operating conditions, pressures will not exceed 110% MOP.

A simplified overpressure protection diagram showing the system from refinery tankage to Bayview station MV 1902 will also be provided to the City by OPL. The drawing will indicate all pressure safety devices including switches, relief valves, hardware/software interlocks intended to prevent overpressure, as well as pump impeller size, all check valves, remote block valves and control valves that can be a source of overpressure on this segment. Shippers will certify that this data represents worst head case scenarios to the pipeline.

11.2. Control Center screens.

OPL will document that the information identified in section 11.1 above is clearly displayed on the SCADA screens and that the purpose and use has been communicated to all controllers.

Attest: *[Signature]*
BELLINGHAM CITY ATTORNEY
BY *[Signature]*

[Signature]
9/10/99
[Signature]
9/10/99

EXHIBIT BMC-53



Federal Register

**Friday,
December 1, 2000**

Part III

Department of Transportation

Research and Special Programs Administration

49 CFR Part 195

**Pipeline Safety: Pipeline Integrity
Management in High Consequence Areas
(Hazardous Liquid Operators With 500 or
More Miles of Pipeline); Final Rule**

DEPARTMENT OF TRANSPORTATION

**Research and Special Programs
Administration**

49 CFR Part 195

[Docket No. RSPA-99-6355; Amendment
195-70]

RIN 2137-AD45

**Pipeline Safety: Pipeline Integrity
Management in High Consequence
Areas (Hazardous Liquid Operators
With 500 or More Miles of Pipeline)**

AGENCY: Research and Special Programs
Administration (RSPA), DOT.

ACTION: Final rule.

SUMMARY: This final rule specifies regulations to assess, evaluate, repair and validate through comprehensive analysis the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. OPS is requiring that an operator develop and follow an integrity management program that provides for continually assessing the integrity of all pipeline segments that could affect these high consequence areas, through internal inspection, pressure testing, or other equally effective assessment means. The program must also provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the assessment and evaluation, and ensuring additional protection to the segments and the high consequence areas through preventive and mitigative measures.

Through this required program, hazardous liquid operators will comprehensively evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. This includes analyzing information on the potential for damage due to excavation; data gathered through the required integrity assessment; results of other inspections, tests, surveillance and patrols required by the pipeline safety regulations, including corrosion control monitoring and cathodic protection surveys; and information about how a failure could affect the high consequence area.

The final rule requires an operator to take prompt action to address the integrity issues raised by the assessment

and analysis. This means an operator must evaluate all defects and repair those could reduce a pipeline's integrity. An operator must develop a schedule that prioritizes the defects for evaluation and repair, including time frames for promptly reviewing and analyzing the integrity assessment results and completing the repairs. An operator must also provide additional protection for these pipeline segments through other remedial actions, and preventive and mitigative measures.

DATES: Effective Date: This final rule takes effect March 31, 2001.

Compliance Dates: An operator must complete an identification of all pipeline segments that could affect a high consequence area no later than December 31, 2001. An operator must develop a written integrity management program no later than March 31, 2002.

Comment Date: Interested persons are invited to submit comment on the provisions of the rule concerning actions an operator must take to address integrity issues on the pipeline (§ 195.452(h)) by March 31, 2001. At the end of the comment period, we will publish a document modifying these remedial action provisions or a document stating that the provisions will remain unchanged.

ADDRESSES: Comments limited to the provisions on actions an operator must take to address pipeline integrity issues (§ 195.452(h)) must be sent to the Dockets Facility, U.S. Department of Transportation, Room PL-401, 400 Seventh Street, SW, Washington, DC 20590-0001. It is open from 10:00 a.m. to 5:00 p.m., Monday through Friday, except federal holidays. You also may submit written comments to the docket electronically. To do so, log on to the following Internet Web address: <http://dms.dot.gov>. Click on "Help & Information" for instructions on how to file a document electronically. All written comments should identify the docket number stated in the heading of this rule.

FOR FURTHER INFORMATION CONTACT: Mike Israni, (202) 366-4571, or by e-mail: mike.israni@rspa.dot.gov, regarding the subject matter of this final rule, or the Dockets Facility (202) 366-9329, for copies of this final rule or other material in the docket. All materials in this docket may be accessed electronically at <http://dms.dot.gov>. General information about the RSPA/Office of Pipeline Safety programs may be obtained by accessing OPS's Internet home page at <http://ops.dot.gov>.

SUPPLEMENTARY INFORMATION:

Background

Notice of Proposed Rulemaking

On April 24, 2000, OPS published a notice of proposed rulemaking (65 FR 21695) that proposed pipeline integrity management program requirements for hazardous liquid operators that operated 500 or more miles of pipeline. The proposed requirements were to apply to hazardous liquid pipelines that could affect areas we proposed as high consequence areas—populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways.

OPS issued the proposal after a public meeting that OPS hosted on November 18 & 19, 1999, to gather information on current pipeline assessment methods and integrity management programs. OPS had also established an electronic public discussion forum to gather further information. Comments and information gathered from these forums were used in developing the proposed rule for larger hazardous liquid operations. The proposed rule was the first in a series of rulemakings that will require all regulated pipeline operators to have integrity management programs.

The notice proposed that a hazardous liquid operator develop and follow an integrity management program. Among the proposed required elements of a program were—

- Baseline assessment of all pipelines that could affect a high consequence area. The integrity of these pipelines was to be assessed by internal inspection, pressure test, or equivalent alternative new technology. The assessment had to be completed in seven years, with 50% of the pipeline mileage done in three and one-half years.

- Continual assessment of all pipelines that could affect a high consequence area. An operator would have to continue to assess, at intervals not to exceed ten-years, and periodically evaluate the integrity of the pipelines.

- Data integration. An operator would have to integrate all information about the pipeline from diverse sources to analyze the entire range of threats to a pipeline's integrity.

- Prompt remedial action. An operator would have to take prompt action to address all integrity issues raised by the integrity assessment and data integration analysis.

- Preventive and mitigative measures. An operator would have to evaluate the need for additional measures to prevent and mitigate pipeline failures, such as installing emergency flow restricting devices (EFRDs) and establishing or

modifying systems that monitor pressure and detect leaks.

- Performance measures to measure the effectiveness of the program.

The proposed rule permitted two options in establishing baseline and continual assessment schedules. An operator choosing the first option would have to base the schedule on specified risk factors. With the second option, an operator would base the schedule on risk factors the operator considered essential in risk or consequence evaluation.

The NPRM explained in great detail the background of the proposed rule for the integrity management program (65 FR 21695; April 24, 2000).

In the NPRM, we said that we intended to apply integrity management program requirements to all regulated pipeline operators but that we would implement the requirements in several steps; when we were done, all regulated operators would be required to have an integrity management program. We explained that because natural gas and hazardous liquid have different physical properties, pose different risks, and the configuration of the systems differ, and because we needed to gather more information about smaller liquid operations, we were beginning the series of integrity management program proposals with hazardous liquid operators operating 500 or more miles of pipeline. We further stated that proposed regulatory requirements for the other operators would soon follow.

The proposed rulemaking was the culmination of experience gained from inspections, accident investigations and risk management and system integrity initiatives. This experience was the foundation for proposing a rulemaking that addressed in a comprehensive manner NTSB recommendations, Congressional mandates and pipeline safety and environmental issues raised over the years. To recap the history of the rulemaking—

- The rulemaking addressed several recommendations NTSB made to OPS concerning pipeline safety.

(1) Require periodic testing and inspection to identify corrosion and other time-dependent damages.

(2) Establish criteria to determine appropriate intervals for inspections and tests, including safe service intervals between pressure testing.

(3) Determine hazards to public safety from electric resistance welded (ERW) pipe and establish standards for leak detection, and expedite requirements for installing automatic or remote-operated mainline valves on high-pressure lines in urban and environmentally sensitive

areas to provide for rapid shutdown of failed pipeline segments.

- Our analyses of several pipeline ruptures in Bellingham, Washington; Simpsonville, South Carolina; Reston, Virginia; and Edison, New Jersey, brought to light the need for operators to address the potential interrelationship among failure causes and to implement coordinated risk control actions to supplement the protection of the regulations.

- The rulemaking also addressed several Congressional mandates to OPS concerning areas where the risk of a pipeline spill could have significant impact.

(1) 49 U.S.C. 60109(a)—prescribe standards establishing criteria for identifying gas pipeline facilities located in high-density population areas and for hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists, or are located in a high-density population area, or are located in an area unusually sensitive to environmental damage (USAs).

(2) 49 U.S.C. 60102(f)(2)—prescribe, if necessary, additional standards requiring the periodic inspection of pipelines in USAs and high-density population areas, and those crossing commercially navigable waterways, to include any circumstances when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline.

(3) 49 U.S.C. 60102(j)—survey and assess the effectiveness of emergency flow restricting devices (EFRDs) and other procedures, systems, and equipment used to detect and locate hazardous liquid pipeline ruptures, and to prescribe standards on the circumstances where an operator of a hazardous liquid pipeline facility must use an EFRD or such other procedure, system, or equipment.

Risk Management and Inspection Initiatives

The proposed rulemaking was also based on what we had learned about integrity management programs from our risk management and pipeline inspection activities, particularly the Risk Management Demonstration Program, the Systems Integrity Inspection (SII) Pilot Program and the new high impact format for inspections. (These programs and activities are discussed in greater detail in the NPRM (65 FR 21695).)

In the Risk Management Demonstration and Systems Integrity Inspection Pilot Programs, we studied and evaluated comprehensive and

integrated approaches to safety and environmental protection. These approaches incorporated operator- and pipeline-specific information and data to identify, assess, and address pipeline risks, in conjunction with compliance with existing pipeline safety regulations. From these programs, we also learned about the extent and variety of internal inspection and other diagnostic tools that hazardous liquid pipeline operators use in their integrity management programs.

OPS implemented a systems approach through a new high impact inspection format that evaluates pipeline systems as a whole rather than in small segments. We found that a system-wide approach is a more effective and, in most cases, more efficient means of evaluating pipeline integrity. As part of this approach, we have been evaluating how pipeline operators integrate information about their pipelines to determine the best means of addressing risk. This experience is helping us to develop detailed inspection guidelines to evaluate compliance with the requirements of this rule.

Advisory Committee Consideration

The Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) is the Federal advisory committee charged with responsibility for advising on the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed hazardous liquid pipeline safety standards. The 15 member committee has balanced membership with individuals having the requisite expertise who represent industry, government, and the general public.

We presented the proposed rule to the Technical Hazardous Liquid Pipeline Safety Standards Committee at its meeting on May 4, 2000. At the request of various committee members, who believed that they had not had sufficient time to review the proposed rule, which was published in April, 2000, formal consideration of the proposal was postponed to September. In preparation for this consideration, the draft cost-benefit analysis was mailed to the members on June 16, 2000 and the members were briefed on the proposed rule in a teleconference on August 24, 2000.

The committee began consideration of the proposed rule at a September 11, 2000 meeting (by teleconference) and completed consideration at a September 22, 2000 meeting (by teleconference). At the September 22 meeting, ten of the eleven participating THLPSSC members voted to accept the proposed rule provided several changes were made.

One member abstained from the general vote, but voted on the individual changes. These changes as well as other comments including minority views are described below. A more complete description can be found in the transcript of the committee's consideration of the proposed rule which is available in the docket.

Various committee members had earlier expressed concern about the quality of the cost-benefit analysis. Concerns expressed included the lack of clear articulation of the benefits and the failure to follow the framework for cost-benefit analysis developed for use in pipeline safety rulemaking. In response to these concerns, OPS committed to revise the cost-benefit analysis to be more consistent with the framework prior to publication of a final rule. Discussion of the issue at the September 22nd meeting indicated that members did not want to delay the issuance of a final rule, but that they believed that the quality of the cost-benefit analysis to be important. The committee voted unanimously that it could not conclude that the proposed rule is reasonable at this time until OPS completed a more meaningful cost-benefit analysis based on the framework. The committee recommended that this be done prior to issuance of the final rule.

In addition, the committee unanimously made the following recommendations for changes to the proposed rule:

- Add pipeline stress to the list of risk factors to be considered in determining the frequency of integrity assessment.
- Clarify OPS's responsibility to identify, generate, publish, and update maps of high consequence areas.
- Establish time requirements for completion of repairs following detection of the defects. The timing may be tiered.
 - Require leak detection capability.
 - Specify the date (for example, January 1995) for acceptability of data from previously conducted internal inspections. This date should be consistent with the proposed 5 year look-back.

With the exception of item 2 (responsibility for maps), RSPA has made changes to the final rule that address each of these recommendations. RSPA is addressing item 2 in this preamble, under the topic heading "Definition of High Consequence Areas—Identification", rather than in language of the rule. That section describes the process through which RSPA intends to make maps identifying high consequence areas available to the operators and the public.

In addition to the formal recommendations of the committee, individual committee members raised two issues about which there was general agreement. The first of these concerned the need to clarify the applicability of the rule to offshore areas. This issue is addressed under the topic heading "Applicability (Coverage) of the Rule." The second of these was the need to clarify the use of internal inspection to assess the integrity of pre-1970 electric resistance welded (ERW) pipe. The committee member was concerned that a footnote in the proposed rule would preclude internal inspection of this type of pipe. Accordingly, RSPA has modified the rule to address the issue. We discuss the rule modification later under the topic heading "Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria."

Prior to the meeting, one committee member had raised the issue of requirements for emergency flow restricting devices. RSPA had indicated that it was considering including criteria for requiring the use of such devices. After a brief discussion in the meeting, the member decided not to pursue a formal recommendation by the committee. As discussed later in the Preamble under the topic heading "Requirements for Preventive and Mitigative Measures, including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Devices", RSPA has modified the rule's provisions concerning emergency flow restricting devices.

There was some discussion in the various meetings that indicated some concern about how RSPA would be able to enforce broad requirements for programs. Some committee members suggested the need for specific criteria that inspectors could apply in reviewing an operator's program. Although these discussions did not result in formal recommendations by the committee, RSPA has included additional specificity in the final rule that will aid in reviewing integrity management programs. In addition, enforceability is discussed elsewhere in this preamble.

The committee also discussed three other issues about which there was not general agreement. Four members of the committee believed that the final rule or a future modification should require leak detection systems and specify performance standards for those systems. The proposed rule did not propose to require or set standards for leak detection systems. (Current regulations require computational pipeline monitoring leak detection systems to comply with API 1130, the

industry consensus standard.) Industry members raised concerns about the scope of the current proposed rule and offered to brief the committee at a future meeting on the range of leak detection systems currently available. As noted above, the committee finally recommended by unanimous consent that the final rule require that pipelines affecting high consequence areas have the capability of detecting leaks. As explained later in the Preamble under the topic heading "Requirements for Preventive and Mitigative Measures, including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Devices", we have revised the rule to address this recommendation.

A second area of discussion about which there was not agreement was a motion to reduce the time for completion of the initial baseline assessment from seven years to three years. RSPA's rationale for not reducing this time frame is discussed elsewhere in this preamble.

The third area was a motion to reduce the time interval for subsequent assessments from ten years to five years. The committee was evenly divided on this issue. As discussed elsewhere in this document under the heading "Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria", RSPA has decided to modify the time interval for integrity re-assessments subsequent to the baseline assessment.

Comments to NPRM

- We received comments from 36 sources in response to the NPRM:
- 2 Trade associations with members affected by this rulemaking
 - American Petroleum Institute (API)
 - American Water Works Association (AWWA)
 - 3 Trade associations with members not directly affected by this rulemaking
 - American Gas Association (AGA)
 - New York Gas Group
 - Interstate National Gas Association of America (INGAA)
 - 8 Individual liquid operators
 - Tosco Corporation
 - Chevron Pipe Line Company
 - BP Amoco
 - Colonial Pipeline Company
 - Koch Pipeline Company
 - Equilon Pipeline Company
 - Enbridge (U.S.) Inc. and Lakehead Pipe Line Partners
 - Dynegy Midstream Services
 - 4 Operators not directly affected by this rulemaking
 - The Peoples Gas Light and Coke Company (LDC and intrastate)

- Tennessee Gas Company (natural gas transmission)
Enron Pipeline Group (natural gas transmission)
Consumers Energy (natural gas transmission and distribution)
- 2 State agencies
Lower Colorado River Authority (LCRA)
State of Missouri—Department of Natural Resources
- 6 Advocacy groups
Robert B. Rackleff, Friends of the Aquifer
Pipeline Survivor's(sic) Association
Environmental Defense
National Pipeline Reform Coalition
Fuel Safe Washington
Harry S. Kottke and Delbert L. Moine, representing Ohio Pennsylvania Landowners Association (OPLA)
- 4 Federal agencies
Environmental Protection Agency, Region III
Environmental Protection Agency, Oil Program Center
Department of Energy
National Transportation Safety Board
- 2 Cities
Austin, Texas
Bellingham, Washington
- 3 Consultants/Contractors
Batten and Associates
Dr. Neb I. Uzelac
SEFBO
- 2 Individuals
U.S. Senator John Breaux
Dene Miller Alden

General Comments

Virtually all commenters were supportive of the need for additional and stronger regulations in this area, and provided comments and suggestions focusing on specific details and language of the proposed rule. Commenters generally fell into one of two groups: those that thought the general structure of the proposed rule was adequate and provided the appropriate balance between prescriptive requirements and pipeline-specific analysis, and those that believed the proposed rule was not sufficiently strong, broad enough in scope, or specific.

All commenters were positive about the need for additional communication among industry, public safety officials, regulators, and the public concerning pipeline risks. We have decided to address the topic of public communication and interaction in a subsequent related rulemaking. We will address these comments in more detail in that rulemaking.

The trade associations and operators that are not directly affected by this rulemaking provided comments in

anticipation of future integrity management program regulations that would affect them. We will use these comments when preparing the proposed rulemakings for the other operators.

We have summarized the comments we received under the following topic areas:

1. Clarity and Specificity in the Proposed Rule
2. Remedial Actions
3. Review, Approval, and Enforcement Processes
4. Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria
5. Applicability (Coverage) of the Rule
6. Consensus Standard on Pipeline Integrity
7. Definition of High Consequence Areas
8. Requirements for Preventive and Mitigative Measures, including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Devices
9. Methods to Measure Program Effectiveness
10. Cost Benefit Analysis
11. Information for Local Officials and the Public
12. Appendix C Guidance

In addition, there were a variety of technical comments and suggestions concerning specific details of proposed Appendix C, and other technical language in the proposed rule. We did not include discussion of these detailed technical comments here but we did consider them in preparing the final rule and revising the Appendix.

RSPA personnel also had numerous discussions with representatives from several federal government agencies during this rulemaking to resolve issues the agencies had raised about the proposed rule. These agencies included the Environment and Natural Resources Division of the Department of Justice, (DOJ/ENRD); Fish and Wildlife Service (FWS), Bureau of Land Management, Office of Environmental Policy and Compliance and National Park Service from the Department of the Interior (DOI),¹ the Office of Ground Water and Drinking Water, Oil Program Center, and Region 3 from the Environmental Protection Agency (EPA); the National Transportation Safety Board (NTSB), the Council on Environmental Quality (CEQ); and the Office of Management and Budget. Where we have made changes to the rule to address comments

¹ The Department of the Interior submitted comments to the docket in the USA rulemaking (RSPA-99-5455). We will consider and address those comments in that rulemaking. The DOI comments we discuss in this rulemaking were made during the inter-agency meetings.

these agencies raised during the discussions, we have so indicated.

1. Clarity and Specificity in the Proposed Rule

The proposed rule used primarily performance-based language to allow operators to use pipeline- and location-specific information to determine the necessary integrity management practices. The proposed rule used specification language to prescribe the required elements of an integrity management program and baseline assessment plan, the allowable methods of integrity assessment and the required intervals for conducting baseline and continual assessments. The proposed rule also specified that an operator was to follow best industry practices unless a rule section specified otherwise or the operator could justify reasons for deviating from such practices and that the deviation was supported by a reliable engineering evaluation.

The proposed rule recognized that an integrity management program was an evolving program that an operator needed to continually improve.

API and the liquid operators supported the proposed rule's holistic approach to pipeline integrity management that incorporated risk assessment and risk-based decision making. API further praised the use of performance-based language in OPS's regulations. Koch commented that "a pipeline integrity management program allows an operator to consider the unique factors that impact a specific pipeline or pipeline segment and is more effective in improving pipeline safety than prescriptive regulations that treat all pipelines, no matter what their characteristics or where they are located, the same."

Environmental Defense, other advocacy groups, and other commenters maintained that the rule should have more specific requirements. These commenters stated that without such specificity, OPS would not be able to evaluate the adequacy of operator programs and enforce the rule. The City of Austin cautioned against a performance-based approach and urged us to clearly define the performance requirements and standards for monitoring, inspection and response.

NTSB reiterated its ongoing concern that OPS have regulations that contain measurable standards for performance.

EPA Oil Program Center commented that the proposed rule failed to include the specific requirements for an integrity management program or the process for determining if a pipeline will affect a high consequence area. The City of Austin said the rule should

require an operator to determine the potential impact for a worst case spill. Colonial Pipeline recommended that the rule clarify, either in the regulatory language or through guidance, how pipelines outside the high consequence area could affect the area.

API recommended that the rule recognize the value of planning changes and allow an operator to make changes to the baseline assessment plan.

DOJ/ENRD expressed concern that the proposed rule's language about an integrity program being an evolving program that an operator had to continually improve left too much to the operator's discretion. DOJ/ENRD had similar concerns with the language about an operator using and documenting a practice other than a standard industry practice. DOJ/ENRD further thought a deviation from a standard practice should only be allowed when new technology is being used. DOJ/ENRD also strongly urged substantial revisions of the proposed rule to improve its enforceability. DOJ/ENRD wanted clearly stated and unambiguous requirements for specific actions that achieve measurable results, the violation of which subject the operator to meaningful penalties.

NTSB expressed concern about the proposed rule's use of the term best industry practices without explaining where these practices could be found. EPA Region III also questioned who would be responsible for establishing, compiling, and disseminating the best industry practices.

API commented that the term best industry practices may cause controversy over its meaning and suggested that the term proven industry practices would be more appropriate.

Response:

To achieve effective integrity management programs that evolve and take advantage of changing technologies, the final rule uses both performance and specification-based language.

Based on our considerable experience with performance-based regulations, OPS believes that performance-based language will best achieve effective integrity management programs that are sufficiently flexible to reflect pipeline-specific conditions and risks.² However, we recognize that certain elements of the rule need to be written in specification language.

Performance-based standards allow an operator to select the most effective

processes and technologies as they become available. OPS wants to create incentives for operators to invest in the development of new technology. Because internal inspection technology and other integrity monitoring equipment have changed considerably in recent years and are expected to continue to improve, we want to encourage operators to use and strive to improve the best available technologies and processes. Thus, rather than only specify the use of currently available technologies, parts of the rule are performance-based to allow operators to develop customized programs that address pipeline-specific characteristics, are fully integrated into company safety and environmental protection programs, and use the best available technologies to assess and repair pipelines.

The specification parts of the rule ensure uniformity among integrity management programs so that they all address key issues, such as baseline and continual integrity assessment intervals, information integration and analysis requirements, and time frames to review and analyze integrity assessment results and to complete remedial actions.

As suggested by commenters, we have revised the rule to allow an operator to modify its baseline assessment plan and to clarify the basis for an operator changing and improving its integrity management program. We have added a provision allowing an operator to modify its baseline assessment plan so long as the operator documents the modification and reasons for the modification. An operator would have to document any modification at the time the decision is made to modify the plan, not at the time the modification is implemented. OPS enforcement personnel would review these supporting documents during a field inspection.

Although reworded, the rule still provides that an integrity management program is a continually changing program. However, the rule now specifies that an operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. The rule also clarifies that an operator's integrity management program will evolve from the initial program framework the operator develops.

We have revised the rule to clarify that the integrity management program requirements apply to each pipeline segment that could affect a high consequence areas. An operator's

program must address the risk factors each pipeline segment poses to a high consequence area.

The proposed rule specified required elements of an operator's integrity management program. Other than some minor word changes and edits, we have not changed those elements in the final rule. We believe these elements will ensure sound integrity management programs.

However, to address commenters' concerns that the proposed rule failed to specify a process for determining if a release could affect a high consequence area, we have added two related requirements: that, as a first step, an operator identify all pipeline segments that could affect a high consequence area and also include a process in its program for identifying which pipeline segments could affect a high consequence area. (Identifying those segments that could affect an area involves determining if a release from a segment in or near a high consequence area could affect the area.) Although we did not propose these requirements in the notice, we believe they were implicit. Whether explicitly stated or not, an operator would have to identify which pipeline segments could affect a high consequence area before determining how the line pipe in those segments would be assessed. Moreover, since the trigger for the integrity management program requirements is whether a pipeline segment could affect a high consequence area, an essential element must be a process for identifying those pipeline segments that could affect the defined high consequence areas. In the Appendix to the rule, we have also provided guidance to help an operator in identifying high consequence areas and in evaluating how a pipeline release could affect a high consequence area. This guidance will help an operator in developing the required process.

The final rule requires that an operator follow recognized industry practices unless the rule otherwise requires a different practice or the operator can demonstrate that an alternative practice is supported by a reliable engineering evaluation. Paragraph (b)(3) does not affect an operator's obligation to comply with all other requirements in this rule. In the final rule, we have changed the term best industry practices to recognized industry practices. We believe this is an easily understood term by operators and enforcement personnel. Recognized industry practices include those found in national consensus standards or reference guides, and generally conform to the practices of the American

² Our using performance-based language in the rule is consistent with the Administration's policy of using performance-based standards. (See Executive Order 12866, Section 1(b) The Principles of Regulation (September 30, 1993).)

National Standards Institute. Companies' successful use of these practices helps determine their validity and acceptance. We have further revised the provision to clarify the basis for an operator using an alternative practice. The rule now provides that an operator's selection of an alternative must be based on a reliable engineering evaluation. Use of an alternative must provide an equivalent level of public safety and environmental protection. An operator must document its use of an alternative practice from when the operator makes the decision to use the alternative. An operator must be able to provide the documentation to OPS enforcement personnel for review during a field inspection.

We have not limited an operator's use of alternative practices to only when new technology is being used. For example, an alternative practice could be one that has been successfully used in other countries or by other pipeline companies but has not yet been codified into a national consensus standard. OPS wants to encourage operators to use innovative practices that are based on sound engineering judgment. OPS also wants to encourage innovation in technology and recognizes that an existing technology may be improved and given a new application.

We have also revised language throughout the rule to make the rule clearer and more understandable. These changes have not affected the requirements of the rule, most have simply been made to improve the rule's overall clarity and to ensure the consistency in use of terms. Others have been made to address DOJ's concerns about making the rule more specific and enforceable and clarifying the operator's required responsibilities under the rule. Any substantive changes are discussed in this document.

2. Remedial Actions—Proposed Section 195.452(g)

The proposed rule required an operator to take prompt action to address all pipeline integrity issues raised by the integrity assessment and data integration analysis. The rule proposed that an operator evaluate and repair all defects that could reduce a pipeline's integrity, and establish an evaluation and repair schedule. The rule did not propose time frames for making the repairs, other than an operator could not operate the affected part of its pipeline system until it had corrected a condition presenting an immediate hazard. The NPRM also asked for comment on whether the rule should contain specific time lines for conducting repairs.

API was against specific time lines and said that criteria for when repairs should be implemented could not be reduced to simple statements suitable for inclusion in the rule. API added that the consensus standard will offer guidance to operators. Enbridge stated that a one-size-fits-all time frame for conducting repairs is not practical or technically justified; however, Enbridge said that it supported the goal of ensuring that no imminent hazard is left unaddressed.

Environmental Defense recommended a relatively short time to conduct repairs after serious defects are identified, e.g., one month to complete repairs unless pipeline pressure is significantly reduced. The City of Austin said that the rule should include repair time lines, acceptable methods of remediation and a better definition of what pipeline flaws constitute an immediate hazard. The City of Bellingham also recommended that the rule establish a specific and expeditious deadline for conducting repairs. EPA Region III commented that the proposed rule did not define what conditions constituted immediate hazard conditions.

Peoples Energy commented that the proposed language about which anomalies an operator had to evaluate and repair only applied to defects that could reduce integrity. Peoples Energy pointed out that this determination could not be made until an operator reviewed all data.

DOJ/ENRD questioned the ability to enforce performance-based standards, particularly with respect to the proposed repair provisions. DOJ/ENRD requested that the regulation be written in language that requires an operator to take specific action. DOJ/ENRD based its concerns on its experience with enforcing the Clean Water Act. DOJ/ENRD was particularly concerned that the proposed rule would not ensure that repairs were made before failures occurred and strongly recommended that language be added specifying when an operator would have to make repairs on the pipeline. DOJ/ENRD also strongly urged that the rule include a provision establishing a cut-off time for when an operator had to review and analyze the results from an internal inspection, and recommended a phased-in approach.

Response: We have rewritten the remedial action section of the final rule to accommodate DOJ/ENRD's and other commenters' concerns. To be consistent with the wording used to describe required program elements, we have renamed the section to reflect the broader actions an operator must take to address integrity issues raised by the

assessments. The rule has been revised to specify time frames for reviewing and analyzing the results of an integrity assessment and for completing repairs of certain conditions (see § 195.452(h)).

The rule still requires an operator to take prompt action to address all pipeline integrity issues raised by the integrity assessment and information integration. The rule now clarifies that an operator is required to evaluate all anomalies and repair those that could affect the pipeline's integrity. Prompt action means that an operator must make the repair as soon as practical. However, an operator must prioritize the repairs according to the severity of each anomaly and address first those anomalies that pose the greatest risk to the pipeline's integrity.

The rule now requires that an operator complete repairs according to a schedule that prioritizes anomalies found during the integrity assessment for evaluation and repair. In this schedule, an operator would have to provide for review and analysis of the integrity assessment results by a date certain. The review and analysis must be done by a qualified person (*i.e.*, a person who has the requisite knowledge and technical expertise to review the results and analyze the data.) For the first three years after the rule's effective date, an operator would determine the period by which the results would have to be reviewed and analyzed and commit that date in writing in its schedule. After the third year, an operator's schedule must provide for review and analysis of the integrity assessment results within 120 days of conducting each assessment. The rule allows more flexibility in the first three years so that OPS can review the adequacy of time frames operators establish, and gather sufficient information to determine what the required standard for review and analysis of assessment results should be. OPS recognizes that a time frame depends, in part, on the availability of persons with expertise to evaluate the data. OPS further recognizes that a quality review and analysis takes time. By the end of the third year OPS will have sufficient information to be able to determine if it should revise the 120-day required period.

An operator's schedule also has to provide time frames for evaluating and completing repairs. A qualified person must conduct the evaluation (*i.e.*, a person with the requisite knowledge and technical expertise.) Because an operator must prioritize the repairs, the rule provides that the operator is to base the repair schedule on specified risk factors and pipeline-specific risk factors

the operator develops. For conditions not specified in the rule, the operator determines the schedule for evaluation and repair. However, the rule provides the time frames in which an operator must complete repair of certain conditions on the pipeline. These conditions are listed as immediate repair conditions, 60-day conditions and 6-month conditions. The time frame required for repair starts at the time the operator discovers the condition on the pipeline, which occurs when an operator has adequate information about the condition to determine the need for repair. Depending on circumstances, an operator could have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly, or receives the final internal inspection report.

In the proposed rule we used the term immediate hazard for certain conditions, and referenced § 195.401(b). In the final rule we refer to these as immediate repair conditions and identify several. Under § 195.401(b), an immediate hazard condition requires that an operator shut down the pipeline until the operator has corrected the condition. With an immediate repair condition, as long as safety is maintained, an operator will either be able to temporarily reduce operating pressure or shut down the pipeline until the operator can complete the repair of the condition.

An operator may deviate from the rule's specified repair times if the operator justifies the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. OPS enforcement personnel will review any justifications and supporting documents during site inspections. In certain cases when an operator cannot meet the required schedule and cannot provide safety through a temporary reduction in operating pressure, the operator must notify OPS. This will allow OPS to determine the extent of review needed and if an inspection is needed. The rule specifies how an operator must notify OPS.

In the NPRM we discussed the consensus standard that an ANSI workgroup was developing on integrity management. OPS has been participating in the work group. In the notice, we said that we would consider adopting all, or part of, the standard once it was final, but only after public notice and comment. (More discussion about the consensus standard appears

later in this document under the topic heading "Consensus standard on pipeline integrity.") The standard is not yet final. However, OPS is basing the provisions in section 195.452(h) on initial indications of what will be in the final consensus standard. We believe that the criteria being considered by the standard's workgroup adequately address pipeline integrity concerns because the criteria are based on a structured methodology for evaluation of internal inspection devices data. The methodology is a recognized industry practice. The criteria are also based on well-established consensus standards, such as the American Society of Mechanical Engineers (ASME) B31.4 standard. ASME B31.4 is a widely-recognized and long accepted standard on liquid transportation systems for hydrocarbons, liquid petroleum gas, anhydrous ammonia, and alcohols. (The regulations in 49 CFR Part 195 were developed from ASME B31.4.)

Although a consensus integrity standard is not yet final, we have made available at OPS's website, notes of the meetings, and a peer review draft of the standard on Managing Pipeline System Integrity. The standard is expected to be completed and published in December, 2000.

We recognize that we have completely restructured the section of the rule pertaining to actions an operator must take to address pipeline integrity issues. Because of the extensive changes to this section of the rule, we are allowing 60 days comment on the provisions in section 195.452(h). Based on the comments we receive, we will consider modifying the provisions. At the end of the comment period, we will either issue a modification or a notice stating that the section stands as written.

An operator has one year from the effective date of the rule to develop the framework for an integrity management program. An operator has 3½ years from the rule's effective date to conduct a baseline integrity assessment of the highest risk line pipe segments. An operator is not likely to take remedial actions required by this rule until after the integrity assessment. Thus, remedial action criteria are not needed until some time after the rule's effective date. We expect to issue any modifications so that operators have ample time to incorporate the modifications into their program framework. If we are delayed in issuing the modification so that operators do not have adequate lead time, we will then consider further delaying the compliance date for section 195.452(h). Until OPS announces a modification, operators can base their

program remedial action criteria on those set forth in this rule.

3. Review, Approval and Enforcement Processes

Some commenters questioned why the proposed rule did not provide for adequate and timely OPS review and approval of an operator's baseline plan, integrity assessments, and integrity program. The proposed rule requires an operator to maintain for inspection written documentation of its program and assessment plan, and of any evaluation or analysis made to support a decision or action. The rule did not propose requirements for formal transmittal of baseline assessment plans, assessment results, or integrity management programs to OPS for approval.

Lower Colorado River Authority (LCRA) supported the flexibility of a performance-based approach but cautioned that the commensurate accountability component seemed to be missing. LCRA explained that the proposed rule did not provide a mechanism for OPS review, or approval of critical decisions made by an operator or indicate that OPS would have any involvement in program implementation. The City of Austin maintained that the proposed rule seemed to continue reliance on the regulated community to implement pipeline safety regulations at their own discretion, with only minimal regulatory oversight. The City of Austin cautioned that close regulatory review and oversight are needed and strongly urged OPS to require all integrity management programs to be submitted for OPS approval, as well as assessment reports.

EPA Oil Program Center expressed concern that the proposed rule relied "heavily on a pipeline operator's assessments, assumptions, and evaluations, yet requires no formal approval process by the Office of Pipeline Safety or certification by a third party, such as a Professional Engineer."

Several commenters questioned OPS's ability to adequately enforce the proposed rule because of inadequate data, knowledge, or expertise. EPA Region III stated that the bulk of expertise in this subject area seemed to reside with the pipeline industry because of the proposed rule's reliance on industry's efforts to evaluate and resolve risk issues concerning pipelines. Region III further stated that OPS must obtain and/or develop independent expertise and knowledge for effective oversight. Friends of the Aquifer commented that because of the lack of

accurate data about pipeline spills, OPS would not be able to judge the adequacy of the risk factors included in an operator's plan.

Response: OPS agrees that an effective and credible inspection process is critical to achieving the objectives of the rule. OPS is developing protocols and criteria for detailed inspection of operator baseline assessment plans and integrity management programs to ensure that operators comply with the requirements of the rule, and that operators use structured, documented, and technically defensible processes and models to support assessment priorities and time frames, decisions on remediation, prevention and mitigation, and measures of program effectiveness.

OPS has already developed expertise in enforcing performance-based regulations and in evaluating risk-based decision processes. OPS has contracted for additional training in specific technical areas to improve the qualifications of its enforcement personnel. OPS plans to have a sufficient base of trained enforcement personnel who will review the integrity management programs during on-site inspections of pipeline operators. OPS will contract for any needed technical expertise to supplement the knowledge of its enforcement personnel.

We are not requiring formal approval of an operator's integrity management program or of decisions and analyses made to develop and implement the program. Rather, a multi-disciplined team composed of OPS regional inspectors, and technical specialists from headquarters will conduct integrity management program inspections. In addition, OPS will contract for other technical expertise, as needed. We are also planning how best to involve state pipeline safety inspectors in the review.

We have also added requirements that an operator provide advance notice to OPS when the operator plans to use other technology (other than internal inspection or pressure test) for a baseline or continual integrity assessment or intends to justify a longer continual assessment period. (We discuss these advance notice requirements later in the document.) We determined that an advance notice requirement was necessary in certain instances to give OPS enforcement personnel additional time to review and evaluate an operator's rationale and supporting documentation.

The rule continues to require an operator to document all aspects of its integrity management program so that OPS enforcement personnel can review these documents during an inspection to determine an operator's compliance

with the rule. We have clarified the language in the final rule concerning the types of documents an operator is required to maintain. Required documents include those to support decisions and analyses made, as well as modifications, justifications, deviations, variances and determinations made, and actions taken to implement and evaluate each of the required program elements. This requirement is no different from other requirements in the pipeline safety regulations that an operator maintain current maps and records of its pipeline system, maintain a procedural manual for operations, maintenance and emergencies and maintain other records of tests and inspections. In Appendix C we have provided some examples of records an operator would have to maintain for inspection. We also discuss recordkeeping requirements in greater detail later in this document in the section by section analysis (section 195.452(1)).

4. Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria—Proposed Sections 195.452(b)–(e) and (j)

The notice proposed that an operator develop and follow a written integrity management program within one year after the final rule's effective date. The proposed rule included a seven-year time frame for the baseline assessment, with an operator having to assess 50% of the mileage within 3.5 years, and a ten-year maximum interval for continual integrity re-assessments. The notice proposed that an operator conduct the integrity assessment by internal inspection, pressure test, or new technology that could provide equivalent protection to the other two methods.

The proposed rule disallowed use of a magnetic flux leakage or ultrasonic internal inspection device for a pipeline segment constructed of low frequency ERW pipe or lapwelded pipe susceptible to longitudinal seam failures. This was done to be consistent with current requirements in section 195.303 providing that an operator's program for testing a pipeline on risk-based criteria provide for pressure testing of a segment constructed of either of those types of pipe.

The notice also proposed allowing as a baseline assessment an integrity assessment that an operator had conducted within five years prior to the effective date of a final rule.

The proposed rule permitted an operator to choose between two options in establishing baseline and continual assessment schedules. The first option specified risk factors to use in

establishing the schedule. The second option permitted an operator to base the schedule on risk factors the operator considered essential in risk or consequence evaluation. This option would have given an operator some flexibility to establish re-assessment intervals exceeding ten years.

Implementation

API recommended that program implementation be keyed to OPS making available to operators a complete set of maps designating the high consequence areas rather than to the final rule's effective date.

The National Pipeline Reform Coalition objected to the one-year program development period based on OPS's estimate in its cost/benefit analysis of how long it would take an operator to develop an integrity management program. OPS had estimated 430 hours.

Assessment Time Frames

API and the industry commenters suggested that OPS establish January 1, 1995 as the cut off date for acceptability of prior integrity assessments, rather than tying the cutoff date to a final rule date. Enbridge and Lakehead asked that operators be allowed to justify older assessments, rather than OPS arbitrarily excluding those older than five years.

API also said that the proposed seven-year baseline and ten-year re-assessment periods were reasonable, and would allow operators to make decisions based on the characteristics of their pipeline system. The hazardous liquid operators re-iterated and concurred with API's comments.

Advocacy and environmental groups, and other commenters objected to the proposed seven-year baseline assessment and ten-year re-assessment periods. Some also objected to allowing a five-year old prior assessment to satisfy the baseline assessment. Environmental Defense suggested a three-year maximum, only allowing baseline assessments that have occurred within two years of the rule. For the continual re-assessment interval, Environmental Defense recommended that OPS follow the California model, and require re-assessment every five years. The City of Bellingham suggested that baseline assessments should be completed in one to three years, and periodic updates within five years. Fuel Safe Washington objected to allowing any prior baseline assessments, and suggested that baseline assessment be completed within 18 months, and that re-assessment be required at a maximum of five years, three years for pipelines constructed prior to 1970, and one year

for pipelines located in unusually sensitive environmental areas. Pipeline Survivor's Association argued that baseline assessments should be completed in three years, with 50% of that mileage being assessed in 18 months, prior assessments be limited to one year before the rule, and re-assessments intervals be shortened to five years. The City of Austin recommended five years for establishing the baseline, 2.5 years to complete 50% of the baseline, and five years for reassessment. Batten & Associates recommended a baseline assessment period of three years, limiting prior allowable integrity assessments to one year before the rule's effective date, and re-assessment intervals of three years. LCRA recommended a seven-year time frame for completing the baseline integrity assessment and shortening the ten-year time frame for re-assessment in some instances based on pipeline-specific risk factors (e.g., age of pipe, leak history, etc.).

Several federal agencies also objected to the proposed integrity assessment time frames. NTSB urged us to reduce the period for the baseline assessment because it could not find sufficient data in the proposed rule to justify the seven-year period. EPA Oil Program Center suggested a five-year time frame for completing the baseline, with 50% of the mileage completed within 30 months. EPA Region III also recommended a five-year continual assessment period because it would provide useful integrity/deterioration information, without imposing too great a burden. DOJ/ENRD raised concern with the proposed seven-year baseline and ten-year continual assessment intervals and strongly recommended shorter baseline and continual integrity assessment intervals. DOJ/ENRD said OPS could not demonstrate that defects would not propagate to failure within the proposed seven-year period. DOJ/ENRD also questioned the basis for OPS's assumption that a ten-year interval was reasonable if a pipeline was adequately cathodically protected.

Assessment Schedule Criteria

The City of Austin recommended eliminating Option 2—allowing an operator to establish an assessment schedule based on factors it determines essential—because it would not be feasible for an operator to demonstrate “an equivalent level of safety and environmental protection as Option 1 given the extremely complex inter-workings of the many potential risk factors.” The advocacy groups argued for dropping Option 2 from the rule because it provided the operator too

much discretion. EPA Region III also stated that Option 2 may provide “too loose a regimen” and supported the approach described in Option 1. Environmental Defense preferred “a modified Option 1 in which operators could identify and report any additional risk factors to those specified in the rule.” The National Pipeline Reform Coalition also recommended eliminating Option 2 because Option 1 allowed enough flexibility for an operator to determine that a specified risk factor had little or no applicability to its operations and discount the factor.

Several commenters suggested risk factors that the rule require for establishing assessment frequency. NTSB recommended that OPS not let an operator determine what factors are essential for ensuring a pipeline system's safety and environmental protection; rather the rule should specify minimum factors that an operator must consider in establishing an assessment schedule. NTSB suggested these factors include the results from previous inspections, the pipeline's leak history, material and coating conditions, cathodic protection history, type of pipe seams, product transported, operating pipe stress levels, defect types and sizes detectable by the inspection method used, defect growth rates, and effectiveness of actions taken to correct chronic problems, such as corrosion. EPA Region III suggested that risk factors for establishing frequency of assessment should also include, product specific differences, location related to the ability of the operator to detect and respond to a leak (e.g., pipelines deep underground) and non-standard or other than recognized pipeline installations (e.g., horizontal directional drilling).

National Pipeline Reform Coalition suggested risk factors such as pipe material and manufacturing processes, highly corrosive soils, and highly volatile products being transported. Dynegy suggested that highly volatile liquids not be treated as other hazardous liquids because they do not pose the same potential for damage to sensitive environmental areas. SEFBO recommended that the rule distinguish overhead suspension pipeline bridges from other above ground pipeline support structures because more sophisticated skills and experience are required to inspect and maintain cable structures. Sen. Breaux also urged that we address the role of these bridges in high consequence areas.

Assessment Methods

API expressed satisfaction that the proposed rule not only recognized that internal inspection tools provide

valuable information but also recognized that a single tool or integrity assessment methodology is not always the answer, and that integrity can be assessed by various inspection methods. API and Equilon, however, suggested that we delete the footnote in the proposed rule preventing operators from using magnetic flux or ultrasonic internal inspection tools on low frequency electric resistance (ERW) welded pipe. API suggested language to ensure that the integrity of ERW seams is adequately assessed. Colonial Pipeline was pleased that the rule recognized the value of internal inspection technology and recognized that technology is constantly evolving.

Koch suggested that the rule allow an alternative assessment methodology in situations where it would be appropriate to conduct an assessment by means other than internal inspection, pressure test, or equivalent new technology. Peoples Energy questioned why the proposed rule did not allow for use of current technology, such as sonic or optical methods, that could be made feasible for pipelines.

Dynegy pointed out that a leak during a hydrostatic test could damage the environment and that installing magnets needed for instrumented internal inspection could also damage an area.

Response:

Implementation

The final rule keeps the one-year period from the rule's effective date for an operator to develop an integrity management program. However, the rule now requires that an operator identify all pipeline segments that could affect high consequence areas within nine months from the rule's effective date. Although implicit that an operator would have to identify the pipeline segments that were covered by the rule, the proposed rule did not propose that an operator do this. Because identification is a necessary first step in the integrity management process, we did not think it unreasonable to make it an explicit requirement.

We have also clarified that during the first year an operator must develop a program framework that addresses each element of the integrity management program. The rule further clarifies that a program begins with the initial framework. Once the program framework is developed, an operator will then have to implement and follow the program. Because an integrity management program is dynamic, the rule provides that an operator must also continually change the program as the operator gains experience.

Assessment Intervals

We have not revised the time period for an operator to conduct a baseline assessment. OPS believes that a seven-year baseline integrity assessment cycle will result in a higher quality integrity assessment and analysis of the assessment results to better ensure the integrity of each pipeline segment. Further, OPS believes that this schedule will effectively double the rate of assessment currently being conducted. Finally, we decided not to establish a shorter baseline interval because an analysis OPS conducted found that internal inspection resources needed to meet demand for baseline assessment are marginally adequate until the year 2007. This finding took into account resources that will be needed concurrently for other assessments (apart from those this rule requires). (See memorandum from Noel Duckworth, dated October 1, 2000. This memorandum is in the docket.) We expect that internal inspection will be the primary choice of operators. Moreover, once we establish similar integrity management program requirements for liquid operators with smaller operations and for natural gas operators, these operators will all be drawing on the same market of vendors. Thus, to ensure that operators have adequate time to conduct high quality integrity assessments and to analyze the results from the assessments, we have kept the seven-year baseline interval.

Moreover, to ensure that the highest risk pipe is assessed early in the cycle, we have clarified that an operator must assess at least 50% of the pipe, beginning with the highest risk pipe, in the first 3.5 years of the seven-year baseline period. This requirement, coupled with the requirement to base the assessment intervals on risk-based factors and analyses, should ensure that an operator assesses the highest risk segments in a shorter time frame. An operator's schedule and rationale for establishing the assessment intervals are subject to review during an inspection.

The rule continues to allow as a baseline assessment an integrity assessment that an operator has conducted five years before the rule's effective date. However, we have revised the rule so that if an operator chooses to use a prior integrity assessment, the operator must then re-assess the pipe segment according to the continual integrity re-assessment requirements (discussed below). We believe that some operators will opt for using a prior integrity assessment to address integrity issues on a pipeline

segment that need prioritized remedial action.

One of the greatest concerns expressed by Federal government agencies, environmental groups and other advocacy groups (as discussed above) was that the proposed ten-year continual re-assessment interval was too long to ensure public safety and environmental protection. Because of the concern expressed, we did additional research and reconsidered the issue. Based on what we found, we have revised the final rule to shorten the continual re-assessment interval. The rule now requires an operator to establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity, unless the operator can demonstrate that one of the limited exceptions applies.

In deciding on the five-year interval, we relied extensively on an analysis OPS conducted on internal inspection devices (Noel Duckworth memorandum dated October 1, 2000). The analysis is available in the docket. The analysis found that, in 1999, the three major internal inspection device vendors in the U.S. logged 30,000 miles, at 68% utilization capacity, and in 2000, the vendors expect to log 45,000 miles at 90% utilization (maximum attainable). According to the memorandum, the analyst estimated that the total capacity of these three internal inspection device vendors would likely increase to about 87,000 miles by 2007. Our current estimates indicate that this rule is likely to apply to 35,500 miles of hazardous liquid pipeline. (Because of the location of pig launchers and receptors, which are typically located near pump stations 50 miles apart, operators will be internally inspecting more than the 35,500 miles of hazardous liquid pipeline required under the rule. We expect that at least 25–30% additional mileage or 44,375 miles will be internally inspected.) Additional internal inspection requirements will also be generated by future rules that will apply to smaller hazardous liquid operators and to natural gas operators. Therefore, according to the Duckworth memorandum, the three big vendors should be able to meet the demand for internal inspection devices, although demand will stress the capacity of the market. The memorandum noted that more is involved in integrity assessment than just running the internal inspection devices, and analyzing the data, but also about the planning/scheduling process between internal inspection tool companies and pipeline operators. Based on these findings, coupled with the insistent urging of several federal agencies (DOJ, NTSB, and EPA), and

many other commenters, who argued that a shorter continual integrity re-assessment interval was essential to protect public safety and the environment, we have reduced the re-assessment interval to a general requirement of five years, providing for exceptions.

The five-year integrity re-assessment period is not absolute. The rule allows variance in limited instances from the five-year period: when there is an engineering basis for a longer period or when the best technology needed to assess the segment is temporarily unavailable. For example, an operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe, if the operator can support the justification by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technologies, that provides an equivalent understanding of the condition of the line pipe. Or an operator may require a longer assessment period for a segment of line pipe because the best assessment technology, given the risk factors of the segment, is not available. An operator would then have to justify the reasons why it could not comply with the required assessment period and also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. In either instance, an operator would have to notify OPS before the end of the five-year period that the operator will be justifying a longer period. If the justification is based on engineering reasons, the operator must provide nine months notice before the end of the five-years. For unavailable technology, the operator must provide 90-days notice. Advance notice will give OPS sufficient lead time to review an operator's justification and supporting documents.

The rule continues to require that an operator base both the baseline and continual assessment intervals on the risk the pipeline segment poses to the high consequence area. To establish the assessment intervals, the rule requires that an operator use specified risk factors, the analysis of the results from the last integrity assessment, and information from the integration analyses. These factors and information will help the operator to prioritize the pipeline segments for assessment.

OPS inspectors will carefully evaluate each operator's methodology for determining the baseline and continual integrity assessment schedules to ensure that the highest risk segments are being addressed in the earliest time frames. OPS inspectors will also review an

operator's justification for deviating from the required five-year re-assessment interval. We have added the requirement for advance notice to OPS when an operator may vary from the five-year interval so that OPS inspectors have adequate time to review and evaluate the justification supporting the variance.

Assessment Criteria

We agree that appropriate flexibility for establishing an assessment schedule based on risk factors can be achieved by modifying Option 1 and deleting Option 2. The final rule requires that an operator base its integrity assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The rule also specifies certain factors that an operator must consider. These factors include those we proposed in the NPRM plus others suggested by NTSB, EPA, the THLPSSC and other commenters. However, the rule does not preclude an operator from including other risk factors specific to the pipeline being assessed. OPS wants to encourage operators to supplement the specified risk factors with factors relevant to the pipeline segment being assessed.

We have not changed the final rule to establish separate requirements for highly volatile liquids and other hazardous liquids, or for overhead suspension pipeline bridges. However, because highly volatile liquids and overhead suspension bridge pipelines may pose unique risks to a high consequence area, an operator's integrity management program must consider and address these risks. In the rule, we have added pipeline suspension bridges and product transported to the list of factors an operator must consider when establishing an assessment schedule. The Appendix provides an operator further guidance on establishing integrity assessment intervals.

Assessment Methods

The rule continues to allow a choice in the integrity assessment method—internal inspection tool, pressure test, or other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. We did not provide for another assessment method in lieu of the three permitted methods. We believe that the three permitted methods give an operator sufficient flexibility to conduct integrity assessments appropriate to each pipeline segment that must be assessed.

The rule provides that an operator choosing assessment by internal

inspection must use a tool or tools capable of detecting corrosion and deformation anomalies, including dents, gouges and grooves.

We have revised the rule to delete the footnote about not using a magnetic flux leakage or ultrasonic internal inspection tool on ERW pipe. We recognize that technology in the internal inspection industry has been changing rapidly. Now, there are readily available tools, for example, ultrasonic (shear wave) and circumferential magnetic flux leakage tools, that can detect longitudinal seam failures. Therefore, the rule now allows an operator to use integrity assessment methods on ERW pipe and on lapwelded pipe susceptible to longitudinal seam failures that can assess seam integrity and can detect corrosion and deformation anomalies. An operator's integrity management program would also have to address the special risks of these types of pipe.

In the final rule we clarified that a pressure test must be conducted according to the requirements for pressure testing found in Part 195, subpart E. An operator choosing to assess by pressure test should also evaluate its corrosion control program before deciding on this option.

OPS inspectors will review the operator's selection of assessment methods for the relevant pipeline segments. OPS personnel will particularly look at the adequacy of the operator's corrosion control program when evaluating an operator's choice to pressure test.

We used the term *new technology* in the proposed rule as an operator's third option. In the final rule, we changed that term to *other technology*. Other technology would include new or existing technology that is adapted for pipeline use and provides an equivalent understanding of the condition of the line pipe as the other two methods. We have also changed the language that the other technology must provide *an equivalent level of protection in assessing the integrity of the line pipe* to that it must *provide an equivalent understanding of the line pipe*. We believe this language better reflects what an assessment tool does i.e., it does not protect the pipe but gives the operator an understanding of the condition of the line pipe.

If an operator chooses other technology as its assessment method, the operator must notify OPS 90 days before using the technology so that OPS has adequate time to review the technology.

5. Applicability (Coverage) of the Rule—Proposed Section 195.452(a)

The proposed rule applied to operators that operate 500 or more miles of hazardous liquid pipeline used in transportation. If an operator fell into that category it would then have to develop an integrity management program for all segments of pipeline that could affect a high consequence area.

EPA Oil Program Center, the National Pipeline Reform Coalition, and other advocates suggested that this rule should apply to all hazardous liquid pipelines. EPA Oil Program Center expressed confusion about whether the rule applied only to pipelines that were 500 miles long or longer. The City of Austin pointed out that smaller operators might be more likely to have poorer maintenance and operating practices. BP Amoco also urged OPS to require all hazardous liquid operators to comply with the proposed rule, expressing concerns that pipeline companies might structure their operations in a manner to avoid applicability of the rule.

NTSB suggested that integrity management requirements should apply to hazardous liquid pipelines no matter where they are located, not just those pipeline segments that could affect high consequence areas.

API and the individual operators commented on the need for greater clarity in the portions of a pipeline facility to which the rule would apply. These commenters said that OPS needed to clarify whether the integrity management program requirements were limited to the line pipe or were intended to cover other facilities included in the definition of pipeline (e.g., pump stations, valves, breakout tanks). The pipeline industry commenters suggested that the rule be limited to the line pipe and that we address integrity issues for the other pipeline facilities in a separate rulemaking.

API also suggested that the final rule clarify that it is limited to onshore pipeline systems, and that OPS conduct a separate rulemaking on integrity management for offshore pipeline systems. API, and other industry commenters, explained that offshore lines may not be capable of accommodating internal inspection devices. API also noted that offshore pipelines pose different risks from onshore pipelines. BP Amoco thought it appropriate to include only offshore pipelines that could affect USAs in an integrity management program because offshore operations pose a limited, if any, risk to public safety. The company

listed technical factors that should be considered in establishing integrity requirements for these lines. Chevron also noted that offshore lines present technical and configurational differences from onshore lines.

SEFBO and Sen. Breaux commented that the rule should clearly distinguish overhead suspension pipeline bridges because of the different skills and experience required for inspection and maintenance of such structures. Dynege recommended that the rule exempt highly volatile liquid product pipelines that traverse wet or flooded areas, instead, that we cover those lines under the gas integrity management program rule.

Response: The final rule clarifies that it applies to each operator who owns or operates a total of 500 or more miles of pipeline used in hazardous liquid transportation. If an operator has 500 or more miles of pipeline in its system, then the operator's integrity management program must address the risks on each pipeline segment in its system that could affect a high consequence area. The length of an individual pipeline segment that could affect the high consequence area is irrelevant to whether it is covered.

Moreover, as we explained in the NPRM, we have no intention of excluding hazardous liquid operators with smaller operations. Our public discussions had given us ample information to proceed with a proposed rulemaking aimed at larger liquid operators. While we proceeded with the first part of the rulemaking (liquid operators owning or operating 500 or more miles of pipeline), we continued to obtain further information about smaller liquid operations so that we could propose integrity management program requirements applicable to those systems. The next step in our series of rulemakings that will ultimately require all regulated pipeline operators to have integrity management programs is to propose integrity management program requirements for hazardous liquid operators who own or operate less than 500 miles of pipeline.

In this rulemaking we have not extended the pipeline integrity requirements to pipelines beyond those that could affect a high consequence area. We continue to focus on pipeline segments that could affect the areas we define as high consequence areas: populated areas, unusually sensitive environmental areas and commercially navigable waterways. However, we expect that many of the measures the rule requires for pipeline segments that could affect high consequence areas will benefit other parts of the pipeline

system not covered by the rule. For example, the final rule requires an operator to analyze and integrate various information about the integrity of the entire pipeline. This analysis is likely to benefit other segments of the pipeline system. The additional preventive and mitigative measures that an operator must take to protect the high consequence area should also yield benefits beyond the segment in the critical area.

Because of the location of launchers and receivers on a pipeline, an assessment by internal inspection is likely to benefit an additional 25–30% of pipeline beyond that covered by this rule. An operator may also choose to extend the integrity assessment beyond the pipeline segment that could affect the high consequence area.

The final rule clarifies the pipeline facilities covered by the integrity management program requirements. The integrity management program requirements apply to each pipeline segment that could affect the high consequence area. We are using the term pipeline as it is defined in § 195.2; the term includes, but is not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, metering and delivery stations, and breakout tanks. Integrity management addresses more than material issues in line pipe, but other issues such as adequacy of procedures, operator training, and other issues related to the pipeline facilities.

The rule clarifies that the baseline integrity assessment, which involves internal inspection, pressure test, or other equivalent technology applies only to the line pipe. (Line pipe is defined in § 195.2.) The continual integrity assessments, done at intervals not to exceed five years, also are limited to the line pipe.

The continual evaluation and information analysis requirements, however, apply to the entire pipeline. To ensure that a high consequence area receives broad protection, an operator must evaluate all threats to and from the pipeline, and consider how operating experience in other locations on the pipeline could be relevant to a segment that could affect a high consequence area. Thus, the rule requires an operator to periodically evaluate the integrity of each pipeline segment that could affect a high consequence area by analyzing all available information about the entire pipeline. This information would include 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; information about how a failure would affect location of water intake; and information gathered in conjunction with other inspections, tests, surveillance and patrols required in Part 195, including, corrosion control monitoring and cathodic protection surveys. This information analysis will be done in conjunction with the periodic evaluation and continual integrity assessment of each pipeline segment.

The rule does not apply to all offshore pipelines, only to those offshore pipeline segments (and onshore pipeline segments) that could affect a high consequence area. Offshore pipelines could, particularly, affect unusually sensitive environmental areas (USAs) and commercially navigable waterways. We are including these offshore pipeline segments because of their potential to impair unusually sensitive ecological resources, to disrupt the flow of goods to communities, or to impair unusually sensitive drinking water resources. We discuss later in this document all areas that are included as high consequence areas. (See discussion under topic heading "Definition of High Consequence Areas.") We also explain how these areas will be shown on the National Pipeline Mapping System (NPMS).

We have also added offshore pipelines to the list in Appendix C of risk factors that an operator should consider in establishing an integrity assessment schedule. Generally, risks associated with offshore lines are because of climatic or geological factors.

We did not accept the recommendation to exempt highly volatile liquid (HVL) product pipelines from this rule. (HVLs are covered under Part 195 because they are and behave like hazardous liquids when transported by pipeline under pressure.) Rather, as discussed previously in this document, we have added highly volatile liquids (or product transported) and pipeline suspension bridges to the list of risk factors an operator must consider in establishing an integrity assessment interval. And as we discuss later in the document, these factors have also been added to the specified factors an operator must consider when analyzing the need for additional protective measures for the pipeline segment.

6. Consensus Standard on Pipeline Integrity

In the NPRM, OPS mentioned that API was sponsoring an American National Standards Institute (ANSI) work group to develop a consensus

standard on integrity management. We said that we expected the consensus standard would provide detailed guidance to operators developing and implementing an integrity management program. We further said that once the standard was final, we would consider adopting it into the integrity management rule, but only after we had provided a public notice and comment period prior to incorporating it into the rule. The work group is continuing its work on the standard and is seeking comment on the draft of the standard.

There was a difference of opinion among commenters concerning an industry group's role in coordinating the development of a standard. Environmental Defense and other public advocates, expressed concern over API's role, and suggested use of a neutral engineering society. The City of Austin urged RSPA to develop standards using a team of stakeholders that includes the regulated community, local officials, experienced safety engineers, and other appropriate experts.

API responded that the standard is being developed using the procedures of the American National Standards Institute and includes broad participation from operators, vendors, representatives from the American Society of Mechanical Engineers (ASME), the National Association of Corrosion Engineers, OPS, and pipeline safety advocates.

EPA Region III said that the pursuit of an industry consensus standard by both the API and OPS is encouraging, but asked about the direct involvement in that process by OPS and other federal agencies, and the current review procedures for such standards.

Response: The standard being developed will be a consensus standard of the American National Standards Institute (ANSI), developed using the standard development procedures of this independent organization. The work group of technical experts includes representatives from government, industry, and members of the American Society of Mechanical Engineers (ASME). When the work group was created in February 2000, environmental and other advocacy groups were invited to join the work group.

The work group's meetings are open to the public. Public participation has been encouraged. Minutes of the meetings have been posted on OPS's website. The resulting draft standard is being distributed for public comment before publishing, allowing input and review from all stakeholders.

The Executive Committee of ASME B31.4 has also agreed, at OPS's request,

to undertake a peer review of this ANSI standard to ensure that the standard adequately addresses the regulatory requirements. The ASME Executive Committee is expected to complete this peer review during fall 2000.

Accordingly, we believe that the ongoing standard development process has the appropriate and adequate checks and balances built in to produce a technically sound product that can support the development and implementation of high quality integrity management programs. We expect this standard will provide more detailed guidance to operators on the specific elements and acceptable processes of an integrity management program, and can supplement the performance-based portions of the rule. Once the consensus standard is final, we will consider adopting, all or part of it into this final rule. However, we will only do so after we have provided for public notice and comment.

7. Definition of High Consequence Areas—Proposed Section 195.450

The proposed rule's definition of high consequence areas had three components: populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways.

Populated Areas

The notice proposed that populated areas consist of high population areas and other populated areas. The proposed rule based these areas on Census Bureau definitions.

The City of Austin thought that the population component of the definition was too vague. They commented that because Census figures were only updated every ten years, that high growth areas could be penalized, and that smaller clusters of dense population would not be included. The City wanted OPS to supplement the Census data with local data on utility connections. The City of Austin also stated that OPS incorrectly stated the Census Bureau's definition of an urbanized area.

USAs

The environmental component of the proposed high consequence area definition used OPS's recently proposed definition of Unusually Sensitive Areas (USAs) (64 FR 73464; Dec. 30, 1999).

Many commented that this proposed definition is too restrictive, and should be expanded to include all environmentally sensitive areas. EPA Oil Program Center expressed concern that OPS's methodology would fail "to protect even the most vulnerable of

sensitive environmental populations and their habitat." EPA Region III said that the definition should include product-specific differences. Friends of the Aquifer stated that "the rule proposes an eccentric and far too narrow definition of natural areas." AWWA also commented that the USA definition was inadequate because it excludes many sources of drinking water. Environmental Defense suggested we include all environmentally sensitive areas without the filtering system the proposed USA definition used. Friends of the Aquifer also wanted all environmentally sensitive areas included. Batten & Associates thought the proposed USA definition was too restrictive and would fail to protect many drinking water resources and habitats for threatened and endangered species.

Commercially Navigable Waterways

API and liquid operators questioned the inclusion of commercially navigable waterways into the high consequence area definition. API pointed out that Congress required OPs to identify hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists and once identified, issue standards, if necessary, requiring periodic inspection of the pipelines in these areas. API said that OPS had not determined the necessity for including these waterways in areas that trigger additional integrity protections. BP Amoco said the rule should be limited to protection of public safety, rather than commercial interests. Enbridge and Lakehead also questioned why waterways that are not otherwise environmentally sensitive should be included for protection.

EPA Region III said that we should also consider recreational and waterways other than those for commercial use. Environmental Defense, Batten, City of Austin and other commented that we should consider all navigable waterways as high consequence areas, because of the environmental consequences a hazardous liquid release could have on such waters.

Other Areas

EPA Region III maintained that product specific differences should be incorporated into the definition. Environmental Defense, Batten and other commenters wanted OPS to expand the definition of high consequence areas to include cultural, recreational, tribal and economic resources. Environmental Defense suggested we include national parks, wilderness areas, and wildlife refuges.

The City of Bellingham asked that we consider addressing integrity management programs for pipeline located outside the high consequence areas.

The City of Austin commented that the definition failed to include areas that are of high consequence due to preservation or recreational value alone. The City suggested including all state, national, and local parkland, refuges and wilderness areas, and preserves designated for water quality protection and wildlife.

API argued against expanding the definition to include cultural resources, environmental resources other than those identified as USAs, and other areas of national importance. They argued that including these areas would dilute available resources and focus from the populated and environmental areas that need greater protection, and that many other Federal, state, and local regulations are in place to minimize the effects of hazardous liquid pipelines on these other areas.

During discussions with representatives from DOJ/ENRD, DOI, and EPA, we were strongly urged to include other areas as high consequence areas: all waters of the United States, wetlands and wildlife refuges, wilderness areas, fish hatcheries, units of the National Park System, and wild and scenic rivers. DOI, DOJ and EPA strongly recommended that the National Parks and National Fish Hatcheries be included in the definition.

Identification of High Consequence Areas

API and liquid operators wanted OPS to clarify its commitment to identify high consequence areas, to generate and publish maps of the areas, and to periodically update the maps. These commenters said that such information was necessary before operators could assess pipelines and take appropriate preventive and mitigative measures.

Response: The final rule continues to focus on areas where we have determined a hazardous liquid pipeline failure could pose the greatest threat to public safety, unusually sensitive environmental areas (including drinking water and ecological resources), and water commerce that is essential for communities' safety and public health or for national security. We have not revised the definition to incorporate product-specific differences; rather, other parts of the rule address the risks associated with different products the pipeline is transporting (e.g., when considering risk factors for establishing assessment intervals).

Populated Areas

In the final rule, we have not changed the definition of populated areas that is based on the Census Bureau's definitions and delineations. We disagree that we misstated the Census Bureau's definition of urbanized areas. The only change we have made is in the terms we are using. What Census Bureau calls an *urbanized area*, we are calling a *high population area*. The additional populated areas that the Census Bureau calls a *census designated place*, we are calling an *other populated area*. We have chosen these definitions to avoid confusion over the term places, which the Census Bureau used to include both urbanized and census designated places. Our National Pipeline Mapping Systems (NPMS) will use the same titles and definitions used in this final rule.

We are using Census Bureau data for the population component because it is the recognized expert and source for general population data in the communities of the United States. The data are standardized, publicly available and in a format that allows OPS and others to create maps of the populated areas. OPS currently does not have the resources to gather local data on utility connections. However, nothing precludes an operator from supplementing the maps we will provide with other data pertinent to its pipeline. (As discussed later in this Preamble under the sub-topic heading "Identification of high consequence areas", an operator will have the ongoing responsibility to incorporate newly-identified populated areas and unusually sensitive environmental areas into its assessment plan.)

Populated areas consist of high population and other populated areas. High population areas are the Census Bureau's urbanized areas. These areas contain 50,000 or more people and have a population density of at least 1,000 people per square mile. Other populated areas are the Census Bureau's places minus the urbanized areas. These areas contain concentrations of people and include incorporated or unincorporated cities, towns, villages, or other designated residential or commercial areas.

We believe the population component of the high consequences area definition picks up most areas where pipelines can pose a threat to public safety. However, we are aware that there may be other areas where people congregate near pipelines, but do not fall within either sub-component of the population definition. Two recent and tragic accidents illustrate the dangers that

pipelines pose to public safety in these areas. In Bellingham, Washington, a pipeline release into a creek ignited and resulted in the deaths of three young people who were in the recreational park through which the creek flowed. An explosion that occurred on one of the three adjacent large natural gas pipelines near Carlsbad, New Mexico, killed 12 people, including five children, who had been camping near the pipeline.

Although this rule is not including areas where people congregate in the high consequence area definition, OPS is considering addressing these areas in a future rulemaking. In the meantime we encourage operators to consider addressing in their integrity management programs areas where people congregate and to determine if there are pipeline segments in or near these areas that could affect the area. Operators should be able to recognize these areas, through fly overs or other surveillance made of their pipelines, or through consultation with local officials in the community.

USAs

The rule's definition of high consequence areas will incorporate the final definition of Unusually Sensitive Areas, which OPS expects to issue in November 2000 (Docket No. RSPA-99-5455). The USA rulemaking will address the resolution of the above comments and other submitted to the docket for that rulemaking. Because of the dependence of this rulemaking on the final definition of USAs, this rule will not be effective until March 31, 2001.

Commercially Navigable Waterways

Our inclusion of commercially navigable waterways for public safety and secondary reasons is not based on the ecological sensitivity of these waterways. Parts of waterways sensitive for ecological purposes are covered in the proposed USA definition, to the extent that they contain occurrences of a threatened and endangered species, critically imperiled or imperiled species, depleted marine mammal, depleted multi-species area, Western Hemispheric Shorebird Reserve Network or Ramsar site. In this rule, only those pipeline segments that could affect a commercially navigable waterway are covered. We are including commercially navigable waterways as high consequence areas because these waterways are a major means of commercial transportation, are critical to interstate and foreign commerce, supply vital resources to many American communities, and are part of

a national defense system. A pipeline release could have significant consequences on such vital areas by interrupting supply operations due to potentially long response and recovery operations that occur with hazardous liquid spills. As explained later, OPS will map these waterways on its National Pipeline Mapping System.

Other Areas

As discussed above, representatives of several Federal government agencies urged us to include other areas in the definition of high consequence areas. We have decided not to include these suggested areas in this rulemaking.

Although we have not included the other suggested areas in this rulemaking, we are considering extending protection to other environmentally sensitive and vital resources through future rulemaking. Other areas that will be considered include National Parks, National Wildlife Refuges, National Wilderness Areas, National Forests, and other cultural resources and sensitive environmental resources that do not meet the USA filtering criteria.

Identification of High Consequence Areas

OPS will identify high consequence areas on its National Pipeline Mapping System (NPMS). Operators, other government agencies and the public will have access to these maps through the Internet. Individuals will be able to view high consequence areas nationally or by state, county, zip code, or zooming in or out of a particular area. An operator will then be able to determine which of its pipeline segments intersect or have the ability to affect a high consequence area.

OPS will identify the locations of USAs through a comprehensive collection and analysis of drinking water and ecological resource data, contingent on the availability of funding and resources.³ OPS will make its USA maps, including the drinking water data, available through the National Pipeline Mapping System. Barring unforeseen resource demands, OPS's current plan is to have the USAs in the top ten states (covering 75% of total

pipeline mileage) available by the end of December 2000. Maps of the USAs in the next ten states (90% of total pipeline mileage) should be available by April 2001. And we plan to have the maps of the remaining states (100% of total pipeline mileage) available by December 2001.

Some of the information that OPS is purchasing, such as discrete sets of ecological data from the Nature Conservancy and other sources, will not be publicly available. Operators may need to contact resource agencies to obtain additional information on a particular species or drinking water intake in an USA.

OPS will use the National Waterways Network database to identify commercially navigable waterways. The commercially navigable waterways map and database will be available through the National Pipeline Mapping System. The Bureau of Transportation Statistics also has a database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website: <http://www.bts.gov/gis/ntatlas/networks.html>.

OPS will use the Census Bureau's data to identify high population and other populated areas. We will use the Census Bureau's urbanized area data to identify high population areas and their places data to identify other populated areas. Their data on places includes both urbanized areas and other populated areas. OPS will filter out the urbanized areas data from the places data so that the resulting map and database will clearly distinguish other populated areas from the urbanized or high population area data. Operators and the public will be able to view the high population and other populated areas maps together or separately on the National Pipeline Mapping System.

OPS recognizes that inventories and maps of high consequence areas have to be updated on a periodic basis to incorporate new information and databases. OPS intends to update the high consequence area maps every five years, contingent on the availability of funding and resources. OPS will review new or revised programs and databases at that time to incorporate appropriate programs and databases into the high consequence area definition and model. OPS will announce in the **Federal Register** and through other communication networks when revised high consequence area maps are available for given areas.

Changes, particularly population changes, will occur around an operator's pipeline. Although OPS intends to periodically update the maps, it remains

an operator's responsibility to keep information about its pipelines up to date. By continually evaluating its entire pipeline and analyzing all available information about the integrity of the pipeline, an operator should be aware of population and ecological changes that are occurring around the pipeline and continue to update its maps and integrity management program to accommodate these changes.

In the rule we have added requirements about how an operator is to incorporate any newly-identified high consequence areas into its baseline assessment plan and integrity program. The rule provides that when an operator has information (from the information analysis or from Census Bureau maps) that the population density around a pipeline segment has changed so as to fall within the definition of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. Similarly, an operator must incorporate a new unusually sensitive environmental area into its plan within one year from the date the area is identified. The rule further requires an operator to complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

We thought it necessary to add these requirements because of the concerns many commenters expressed about who would be responsible identifying high consequence areas and how updates would be handled. Although OPS is taking primary responsibility for mapping these areas, an operator has a corresponding responsibility to continually evaluate its pipeline and update information about the pipeline.

8. Requirements for Preventive and Mitigative Measures, Including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Systems—Proposed Section 195.452(i)

The proposed rule required an operator to conduct a risk analysis to assess the risks to its pipeline system and determine what additional preventive and mitigative measures are needed to protect a high consequence area. The proposal identified possible preventive or mitigative measures an operator could take to protect a high consequence area, such as implementing damage prevention best practices, establishing or modifying leak detection systems, and providing additional training on response procedures.

³ OPS uses state data bases as the primary data source for the USA model. The drinking water USA model relies on data solely provided by the States. State aquifer maps are used to determine aquifer classifications. State data on well location depth, and source are used to identify the aquifers used by the wells. The ecological USA model uses data from the state Natural Heritage Programs (NHP) on rare and endangered species locations. OPS is also using the Environmental Sensitivity Index and related ecological data sets to augment the NHP data.

Installing EFRDs was one of several mitigative measures the rule proposed. However, the proposal did not require an operator to install EFRDs or define the conditions under which an operator should install EFRDs. In the NPRM we specifically invited comment on any needed further guidance to operators on when EFRDs should be installed. We also invited comment on the criteria for evaluating the decision on whether to install an EFRD or to take other measures, and if in certain limited circumstances, we should mandate the use of EFRDs.

EPA Region III supported the preventive and mitigative measures the rule proposed but argued against leaving the need for particular actions to the operator. Region III was concerned that without active and knowledgeable regulatory oversight, strict methodology, or the required participation of a risk assessment professional, an operator would be unlikely to find any of the measures necessary. Environmental Defense said that the rule should include specific requirements for operators to use preventive strategies. NTSB expressed concern with operators using risk management principles to determine the need for additional protective measures and recommended that the rule include minimum criteria.

EPA Oil Program Center said that the rule should prescribe circumstances in which EFRDs or other protective and mitigative measures must be used. EPA Oil Programs further commented that if the rule allows an operator to conduct a risk assessment to determine if EFRDs or other protective measures are needed, then the rule should prescribe a specific risk assessment protocol.

Environmental Defense, Batten and other advocates recommended that the rule include performance standards for leak detection, EFRD spacing and damage prevention best practices. Environmental Defense and Pipeline Survivor's Association recommended that leak detection systems be capable of detecting a leak of one gallon/minute or more and that EFRD spacing prevent releases of more than 10,000 gallons of hazardous liquid into a high consequence area. The City of Austin supported requiring EFRDs in all high consequence areas and that they be spaced to restrict the worst case spill to 10,000 gallons. Batten suggested that leak detection devices be capable of detecting within 15 minutes a leak of ten gallons or more and that pipe segments between EFRDs be able to contain no more than 50,000 gallons when located in a high consequence area.

AWWA encouraged the placement of EFRDs to the greatest extent possible to protect public water supplies, suggesting that EFRDs be used as the standard against which other mitigation strategies are measured. LCRA commented that EFRDs should be required on either side of a river crossing. EPA Region III also encouraged using EFRDs whenever necessary to protect a high consequence area.

API and operators commented that the proposed rule is reasonable and that OPS should ensure risk mitigation decisions made within an integrity management program include considering the use of EFRDs rather than requiring such placement or prescribing minimum spacing. Enbridge and Lakehead supported EFRDs as one of various preventive or mitigative actions an operator should consider but said there was no one distance or placement specification appropriate for all pipeline systems. Many cited research by the California State Fire Marshall, and Southwest Research to support their argument that there are many site and flow-specific factors that operators must consider in making risk mitigation decisions. Several industry commenters also noted the possible environmental disadvantage to EFRDs, including the possibility of valve leakage or inadvertent closure resulting in over pressurization, as well as the environmental impacts of installing and maintaining valves in or near environmentally sensitive areas.

Response: The final rule continues to require an operator to take additional measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. It is up to each operator to conduct a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. For this risk analysis, the rule clarifies that an operator must evaluate the likelihood of a pipeline release occurring, how a release could affect the high consequence area, and what risk factors the operator should consider. The rule continues to list some additional preventive and mitigative measures an operator should consider. The list is not an exhaustive recitation of every preventive or mitigative measure that could enhance public safety or environmental protection.

One of the listed measures is for an operator to modify the systems that monitor pressure and detect leaks. Operators use various procedures and methods to detect the movement of product through the pipeline. For

example, computational pipeline monitoring, SCADA systems, and station sensors, measure deviations from measured values (pressures, flows) beyond established norms. The pipeline safety regulations do not require an operator to have a leak detection system. However, if an operator has a software-based leak detection system, the regulations require the operator to use an industry document (API 1130) in designing, evaluating, operating, maintaining and testing its software-based system. (See § 195.444.) Moreover, whenever a leak detection system is installed or a component replaced, API 1130 must be followed.

The final rule requires an operator to have a means to detect leaks on its pipeline system. (We provide several examples of types of leak detection systems later in this document when we discuss Section 195.452(i).) We have rewritten the rule to require an operator to evaluate the leak detection's capability to protect the high consequence area and to modify, as needed, to protect the high consequence area. The rule includes factors that an operator must consider in making its evaluation. OPS enforcement personnel will review the adequacy of this evaluation process during site inspections.

Another protective measure the rule identifies is for an operator to install an EFRD on the pipeline segment. The final rule does not prescribe the specific conditions under which EFRDs or other preventive or mitigative measures are required. Rather, the final rule requires an operator to develop and apply risk assessment and decision-making processes that reflect pipeline-specific conditions and operating environments. The rule now specifies criteria that an operator must consider when conducting the analysis to identify additional protective measures. An operator is not limited to these criteria; rather, an operator must consider these criteria in addition to all other criteria specific to the pipeline segment.

In the final rule, OPS has not specified the circumstances when an operator must use a particular protective measure or install an EFRD. However, we have revised the rule to require that an operator install an EFRD if the operator determines that one is needed to protect the high consequence area. The rule also specifies factors that an operator must consider in making this determination. OPS will review during inspection the adequacy of the analysis and the appropriateness of the operator's decision on the need to install an EFRD.

OPS has been studying for some time the issue of the optimum placement of emergency flow restricting devices to limit commodity release after the location of the release has been identified. In the NPRM, we explained in detail the research OPS has conducted in this area. (See 65 FR 21695; April 24, 2000.) In addition to comment the NPRM solicited, OPS had previously issued an advance notice of proposed rulemaking asking questions concerning the performance of leak detection equipment and location of EFRDs, and held a public workshop to discuss the issues involved in developing regulations on EFRDs.

Our study of the issue led us to conclude that the decision to install an EFRD should not be mandatory but should be left to the operator. Nonetheless, the rule requires an operator to consider certain specified criteria in deciding whether an EFRD will protect the high consequence area.

OPS is requiring an operator to determine whether to install an EFRD based on the operator's risk analysis, because, we believe, prescriptive valve installation and spacing requirements would ignore the site-specific variables and unique flow characteristics of a pipeline segment. Prescriptive requirements could also overlook the potential sensitivity of a specific high consequence area. For example, locating an EFRD near a body of water to reduce the potential volume released might necessitate locating the valve in sensitive wetlands or a flood plain of a river, which creates myriad other problems. Also, a prescriptive approach detracts from the process of evaluating a host of alternative measures to enhance protection to high consequence areas.

9. Methods To Measure Program's Effectiveness—Proposed Section 195.452(k)

In the NPRM we proposed that an operator's integrity management program include methods to measure whether the program is effective in assessing and evaluating the integrity of the pipelines and in protecting the high consequence areas. NTSB commented that this requirement has to contain unequivocal guidance if operators are to use it to improve their programs, and suggested that we develop measures. EPA Region III commented that a measurement based on some industry-wide average should not be used because it could lower the bar for management, technology, and innovation.

Response: We have not revised the provision on program performance

measures other than to clarify that an operator is to measure the effectiveness of the program on each pipeline segment. In Appendix C we have described types of program measures and included examples of methods that an operator can use to evaluate the effectiveness of its integrity management program.

10. Cost Benefit Analysis

The comments we received on the proposed rule's cost benefit analysis are addressed below under the Regulatory Analyses and Notices section.

11. Information for Local Officials and the Public

In the NPRM, OPS invited comments on how local officials could use and benefit from risk assessment information, how the consequences of potential pipeline failures should be characterized, how risk control actions should be described and what performance indicators would be meaningful. We further said that because of the significance of this issue we planned on extensive discussions with all the stakeholders before proposing communications requirements as part of an integrity management program.

Many provided comments relevant to the issue of communications with local officials. Tosco agreed that research is needed on the types and amount of information to distribute to local officials and made available to the general public to determine the most effective means to keep those entities informed. Environmental Defense, the Pipeline Survivor's Association, and Batten listed information they thought operators should make available to public officials and the public. American Water Works Association strongly supported the need for communication, but provided no specific guidance on content.

Lower Colorado River Authority (LCRA) promoted public involvement in the preparation and implementation of integrity management programs, maintaining that with public involvement, pipeline operators would have a better understanding of the vulnerability of the resources. LCRA further commented that public confidence in the pipeline industry would be enhanced if the results of the integrity assessments were made available. The City of Bellingham also recommended that integrity management programs be developed in consultation with appropriate state and local officials before the operator finalizes the program. The National Pipeline Reform Coalition also

recommended that local communities have a role in developing the programs, citing the evidence of the role of the City of Bellingham in developing a safety plan for Olympic Pipe Line Company.

Response: Requirements for communication of integrity management information to local public officials and to the public will be the subject of a future rulemaking. We will use the comments received in this rulemaking in developing the communications rulemaking. A communications work team, consisting of representatives from environmental and public safety organizations, pipeline companies, and government has formed to aid the Hazardous Liquid Advisory Committee (THLPSSC) in developing communications issues. Notices of meetings of the work group will be published in the **Federal Register**. Notes from the meetings will be posted on OPS's web site.

12. Appendix C Guidance

Proposed Appendix C provided operators guidance on how to prioritize risk factors in determining assessment frequency, how to analyze smart pig inspection results, how to prioritize metal loss features, and what types of smart pigs to use for finding pipeline anomalies. The proposed Appendix also included risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, to help determine if the pipeline segment falls into a high, medium or low risk category.

There were a variety of comments concerning Appendix C. Some addressed the role of Appendix C in the overall rule, and others provided specific technical comments on detailed aspects of the Appendix (which are not summarized here).

API and other liquid operators commented that Appendix C "is not sufficiently rigorous or technically accurate to be used as guidance for prioritizing risk" and provided a list of problems they have identified. API recommended that OPS not include the Appendix in the final rulemaking, but that OPS and the integrity standard work group develop technically accurate, rigorous guidance for prioritizing risk factors.

The City of Austin recommended that Appendix C be included as part of the rule because it specifies how an operator should implement the proposed regulation. Fuel Safe Washington stated that "Appendix C is completely undermined by allowing operators to apply their own weights or values to the risk factors."

Response: An Appendix is guidance that is intended to give advice to operators on how to implement the requirements of the integrity management rule. An Appendix does not have the same force as the regulation itself. An operator does not have to follow the guidance. However, if an operator incorporates parts of the Appendix into its integrity management program, an operator must then comply with those provisions.

OPS continues to believe that the guidance provided in Appendix C will be helpful to operators in developing and implementing their integrity management programs. (Operators may supplement this guidance with the industry consensus standard or choose not to use the guidance.) We also continue to believe that the guidance should not be included in the body of the rule because it would unnecessarily inhibit operators from identifying the best pipeline- and segment-specific tools, risk factors, and repair techniques, and would require changes in the rule as new technologies or information is developed.

The Final Rule

The new section 195.450 titled "Definitions" defines high consequence areas. High consequence areas include—

- Unusually sensitive areas—these areas will be defined in the USA rulemaking (Docket No. RSPA-99-5455) and will include drinking water and ecological resources;
- High population areas—these are areas defined and delineated by the Census Bureau as urbanized areas.
- Other populated areas—these are areas defined and delineated by the Census Bureau as places that contain a concentrated population.
- Commercially navigable waterways—these are waterways where a substantial likelihood of commercial navigation exists.

The integrity management program requirements will apply to pipeline segments that could affect these high consequence areas. OPS will map these areas on its National Pipeline Mapping System, and make the maps publicly available.

This section also defines emergency flow restricting devices to include check valves and remote control valves. This definition is used in § 195.452(i) of the rule that addresses additional preventive and mitigative measures an operator must consider for pipeline segments that could affect a high consequence area.

The new section 195.452 titled "Pipeline Integrity Management in High Consequence Areas" imposes integrity

management program requirements on each operator who owns or operates a total of 500 or more pipeline miles used in hazardous liquid transportation.

For an operator covered by the rule, the rule requires the operator to develop, implement and follow an integrity management program that provides for continually assessing the integrity of those pipeline segments that could affect a high consequence area, through internal inspection, pressure testing, or other equally effective assessment means. An operator's program must also provide for evaluating the segments through comprehensive information analysis, remediating potential integrity problems found through the assessment and evaluation, and ensuring additional protection through preventive and mitigative measures.

Through this required program, a hazardous liquid operator must comprehensively evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the entire pipeline and its relevance to the segment that could affect a high consequence area. Information an operator must evaluate includes information on the potential for damage due to excavation; data gathered through the required integrity assessment; results of other inspections, tests, surveillance and patrols required by the pipeline safety regulations, including corrosion control monitoring and cathodic protection surveys; and information about how a failure could affect the high consequence area.

The final rule requires an operator to take prompt action to address all integrity issues raised by the integrity assessment and information analysis. This means an operator must evaluate all anomalies and repair those could reduce a pipeline's integrity. An operator must develop a schedule that prioritizes the anomalies for evaluation and repair. The schedule must include time frames for promptly reviewing and analyzing the integrity assessment results and completing the repairs. An operator must also maintain, and further protect the integrity of these pipeline segments, through other remedial actions, and preventive and mitigative measures.

Which Operators Must Comply? Section 195.452(a)

This rule specifies pipeline system integrity management program requirements for each operator who owns or operates a total of 500 or more miles of hazardous liquid pipeline. This action covers approximately 87 percent

of all the hazardous liquid pipelines in the United States. Based on the volume of hazardous liquid these pipelines transport, they have the greatest potential to adversely affect the environment.

For an operator covered by this rule, the requirements apply to all the operator's pipeline segments (offshore or onshore), regardless of date of construction, that could affect a high consequence area. The rule specifies how operators must provide additional protection to critical areas (*i.e.*, high consequence areas) through integrity management programs. Further, it assures that these protections will be put in place, with an operator being required to initially assess 50 percent of the line pipe that could affect critical areas, beginning with the highest risk pipe, within 3.5 years and the balance within seven years. An operator will then have to evaluate and repair defects within specified time frames and implement additional preventive and mitigative measures. An operator is also required to continually re-assess its pipeline segments at intervals not longer than five-years, as well as periodically evaluate each pipeline segment by analyzing all available information about the integrity of the entire pipeline, and its relevance to segments that could affect the high consequence areas.

What Must an Operator Do? Section 195.454(b)

The rule requires that, no later than one year after the rule's effective date, an operator must develop a written integrity management program that addresses the risks on each pipeline segment that could affect a high consequence area. An operator must then implement and follow the program it has developed. Initially, the program will consist of a framework. An operator must include in its integrity management program—

- An identification of all pipeline segments that could affect a high consequence area. Because identification of the pipeline segments is the trigger for all other integrity management requirements, the identification must be done within nine months from the rule's effective date.
- A plan for baseline assessment. The assessment of the line pipe must be done by internal inspection, pressure test, or other technology that provides an equivalent understanding of the condition of the line pipe.

- A program framework that addresses each of the required program elements, including continual integrity assessment and evaluation. In the first year after the rule's effective date, the

framework must indicate how decisions will be made to implement each required program element. The framework will evolve into an integrity management program as the operator makes decisions and gains experience. An integrity management program is a dynamic program that an operator must continually change as the operator gains more information about the pipeline and the results of the assessments.

To carry out the rule's requirements, an operator must follow recognized industry practices unless the rule specifies otherwise or the operator chooses an alternative practice that is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection. Recognized industry practices include national consensus standards and practices found in reference guides. Allowing the use of alternative practices in the rule should encourage operators to use innovative technology in implementing the integrity management program's requirements.

What Must Be in the Baseline Assessment Plan? Section 195.452(c)

The rule requires an operator to include in its written baseline assessment plan each of the following elements.

- The methods selected to assess the integrity of the line pipe of each segment that could affect a high consequence area;
- A schedule for completing the integrity assessment;
- An explanation of the assessment methods the operator selected and an evaluation of risk factors the operator considered in establishing the assessment schedule for the pipeline segments.

The rule allows an operator to modify the baseline assessment plan provided the operator documents the modifications and reasons for the modifications. As discussed later under the section on recordkeeping requirements (§ 195.452(l)), these are documents an operator is required to maintain for inspection. Enforcement personnel will look to see that an operator has documented the modification well before the operator has implemented the modification.

OPS expects an operator to make the best use of current and innovative technology in assessing the integrity of the line pipe. Therefore, the rule allows an operator to conduct an integrity assessment by—

- Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents,

gouges and grooves. For electric resistance welded (ERW) pipe or lap welded pipe susceptible to longitudinal seam failures, the rule provides that the integrity assessment methods must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. An operator's program would also have to address any risk factors associated with these types of pipe;

- Pressure test conducted in accordance with Part 195, subpart E; or
- Other technology that provides an equivalent understanding of the condition of the line pipe.

Internal inspection is one of the most useful tools in an integrity management program. We expect an operator to consider at least two types of internal inspection tools for the integrity assessment of the line pipe: *geometry pigs* for detecting changes in circumference and *metal loss tools* (magnetic flux leakage (MFL) pigs or ultra sonic pigs) for determining wall anomalies, or wall loss due to corrosion. Both high resolution and low resolution tools can be beneficial in integrity assessment. For example—

Corrosion/metal loss: With respect to corrosion, high-resolution tools can identify anomalies and, with the use of engineering critical assessments, use a conservative evaluation of the potential for the anomaly to have affected remaining pipe strength (or affected the pressure capacity of the pipeline segment). This assessment uses analytical techniques that estimate average depth of metal loss. Based on the evaluation of internal inspection results, a prioritized listing of potential defects is developed to guide the initiation of the field digging, inspection, confirmation and the necessary repair program. Once in the field, additional calculations based on actual profile of metal loss are used to confirm the need and type of appropriate repair.

High Resolution versus Low Resolution: High-resolution tools can distinguish between internal and external corrosion and provide more extensive information to more accurately assess the potential for an anomaly to pose a risk.

Mechanical Damage: Internal inspection tools to measure dents or geometric deformations are common and are typically run routinely following installation of new pipelines. Technology has advanced such that geometry tools can normally withstand even the most extreme pipeline conditions. The tool is able to pass restrictions (e.g., deformations) of up to 25%, and with the high sensitivity of

gauging systems now on the market and large number of sensing fingers, current tools can detect even very small ovalities (0.6%).

Crack Detection: Since the early 1990's, pipeline operators have successfully field tested internal inspection tools capable of non-destructively identifying fatigue cracks and stress corrosion cracking in the longitudinal seam. Research and development continues on these tools to strive for reliable identification of other types of seam defects, such as hook cracks. With the use of ultrasonic and MFL (transverse orientation) technology, pipeline segments that have experienced fatigue cracking can now be inspected. Cracks with a potential to rupture can be identified and repaired prior to growing to a critical stage. This is particularly important as this type of defect could survive initial and subsequent pressure tests but then with pressure cycling, grow over time to a critical stage and leak or rupture.

The rule also permits integrity assessment of the line pipe by pressure test. An operator must conduct a pressure test according to the requirements prescribed in Part 195, subpart E.

The purpose of a pressure test is to remove defects that might impair the integrity of the pipeline during operation. Defects might exist as a result of the manufacturing process or damage to the pipe during shipping, construction or operation. The defects are identified by failure of the pipe during the test, the defective pipe is removed, new pipe is installed, and the pipe is tested again until no failure occurs. The pressure test provides a margin of safety for the pipeline by being conducted at a pressure higher than the maximum pressure at which pipeline safety regulations allow the pipeline to be operated.

OPS expects that an operator choosing this method of integrity assessment for a pipeline segment will review its corrosion control monitoring program for that segment. OPS inspectors will review these documents when evaluating an operator's choice of pressure test as an assessment method.

To encourage innovation, the final rule also allows an operator to use other technology for the integrity assessment, if the operator demonstrates that an alternative technology can provide an equivalent understanding of the condition of the line pipe as the other permitted assessment methods.

An operator choosing this option must notify OPS at least 90 days before conducting the assessment with the other technology. The rule specifies

how notification can be made: by mail or facsimile. Advance notice is necessary so that OOPS enforcement personnel have adequate time to review the operator's basis for using the technology.

When Must the Baseline Assessment Be Completed? Section 195.452(d)

The rule requires an operator to establish a baseline assessment schedule to determine the priority for assessing the pipeline segments covered by the rule. An operator must complete the baseline integrity assessment within seven years after the rule's effective date. An operator is further required to assess at least 50% of the covered line pipe, beginning with the highest risk pipe, within 3.5 years from the rule's effective date. This requirement, in conjunction with the requirement to base the assessment intervals on risk-based factors, should ensure that an operator assesses the highest risk pipeline segments earlier in the cycle.

The final rule allows an operator to use an integrity assessment method conducted five years before the rule's effective date as the baseline assessment if the method is at least equivalent to the requirements for internal inspection, pressure testing or alternative technology. However, if an operator decides to use a prior integrity assessment as its baseline assessment, the operator must then re-assess the integrity of the line pipe within five years. The re-assessment would have to comply with the continual integrity assessment requirements in § 195.452(j). As we discuss later in this document when explaining § 195.452(j), the rule allows for deviations from the five-year requirement in certain limited instances.

Because population and ecological changes may occur around an operator's pipeline, an operator must, as part of its periodic evaluation and information analysis, keep informed about how such changes are affecting each pipeline segment. If the population density around a pipeline segment changes so as to fall within the definition of a high population area or another populated area, the rule requires an operator to incorporate the area into its baseline assessment plan as a high consequence area. This must be done within one year from when the area is identified. An operator must then assess the integrity of any line pipe that could affect that newly identified high consequence area within five years from when the area is identified. Similarly, the rule requires an operator to incorporate a new unusually sensitive environmental area into its baseline plan within one year

from when the area is identified and to assess the new area within five years.

What are the Risk Factors for Establishing an Assessment Schedule? Section 195.452(e)

For both the baseline and continual integrity assessments, an operator must establish a schedule that prioritizes the pipeline segments for assessment so that the higher risk segments are assessed earlier in the cycle. The rule requires an operator to base the assessment schedule on all risk factors that reflect the risk conditions on each pipeline segment. The rule further specifies some factors an operator must consider in establishing a schedule. An operator is not limited to these factors; rather, an operator must supplement the listed factors with those that are specific or unique to the pipeline segment being assessed.

In Appendix C, we provide guidance to an operator on how to determine risk factors for a pipeline segment and use them to develop an integrity assessment schedule. The guidance includes an example of risk factors that we apply to a hypothetical pipeline segment to establish an assessment frequency.

What Are the Elements of an Integrity Management Program? Section 195.452(f)

The final rule requires an operator to include certain minimum elements in its integrity management program. Initially, an operator must develop a framework containing these elements. The framework evolves into a program as the operator gains experience, makes decisions and implements actions. The required program elements include—

- A process for identifying which pipeline segments could affect a high consequence area. The Appendix gives guidance to help an operator evaluate how a pipeline segment could affect an area, which will help an operator in developing this process. The guidance lists factors an operator needs to consider when evaluating the pipeline segment's ability to affect a high consequence area.
- A baseline assessment plan (discussed in § 195.452(c));
- An analysis that integrates all available information about the integrity of the entire pipeline, its relevance to the particular segment, and the consequences of a failure;
- Criteria for repair actions to address integrity issues raised by the assessment methods and information analysis;
- A continual process of assessment and evaluation to maintain a pipeline's integrity;

- Identification of preventive and mitigative measures to protect the high consequence area;

- Methods to measure the program's effectiveness; and

- A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information. An operator must use qualified persons with the necessary technical expertise to evaluate and analyze the results and data from the integrity assessments, the periodic evaluation, the information analyses, etc.

To be effective, an integrity management program must constantly change. OPS expects that the initial program will consist of a framework that specifies the criteria for making decisions to implement each of the required elements. The program evolves from the framework and must continue to change to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area.

What is an Information Analysis? Section 195.452(g)

The final rule requires an operator to periodically evaluate the integrity of each pipeline segment that could affect a high consequence area by analyzing all available information about the integrity of the entire pipeline and the consequences of a failure. The analysis applies to the entire pipeline to determine the relevance to a particular pipeline segment. Required information an operator must evaluate includes—

- 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 required baseline and continual integrity assessments;
- Data gathered in conjunction with other inspections, tests, surveillance and patrols required in Part 195. This would include information from corrosion control monitoring and cathodic protection surveys;
- Information about how a failure would affect the high consequence area, such as location of the water intake.

Through this requirement to integrate and analyze information from diverse sources, OPS expects an operator to analyze its entire pipeline to evaluate the entire range of threats to each pipeline segment that could affect a high consequence area. An operator will

conduct this analysis in conjunction with the required periodic evaluation discussed below (section 195.452(j)).

What Actions Must Be Taken To Address Integrity Issues? Section 195.452(h)

The rule requires an operator to take prompt action to address all pipeline integrity issues raised by the integrity assessment and information analysis. By prompt action we mean that an operator must prioritize repairs according to the severity of the anomaly and address first those anomalies that pose the greatest risk to the pipeline's integrity. The rule clarifies that an operator must evaluate all anomalies and repair those that could affect the pipeline's integrity. Any repair made must be done according to the pipeline repair requirements in 49 CFR § 195.422.

The rule requires that an operator develop a schedule that prioritizes the anomalies found during the integrity assessment and information analysis for evaluation and repair. In this schedule, an operator would have to provide for prompt review and analysis of the integrity assessment results by a date certain. For the first three years after the rule's effective date, an operator would determine the period by which the results would have to be reviewed and analyzed and commit to that date in its schedule. After the third year, an operator's schedule must provide for reviewing and analyzing the results of the integrity assessment within 120 days of conducting the assessment.

An operator's schedule also has to provide time frames for evaluating and completing repairs. The rule provides that an operator is to base the schedule on specified risk factors and pipeline-specific risk factors the operator develops. For conditions not specified in the rule and those the rule identifies as other conditions, the operator determines the schedule for evaluation and repair. However, the rule provides the time frames in which an operator must complete repair of certain conditions on the pipeline. These conditions are listed as immediate repair conditions, 60-day conditions and 6-month conditions. Of course, the rule cannot identify all conditions that an operator will have to evaluate and repair. A condition an operator discovers may qualify as an immediate repair, 60-day or 6-month condition even though it is not listed in the rule. The rule simply provides common examples of such conditions.

The schedule required for repair starts at the time the operator discovers the condition on the pipeline, which occurs when an operator has adequate

information about the condition to determine the need for repair. Depending on circumstances, an operator could have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly or, receives the final internal inspection report.

An operator may deviate from the rule's specified repair times (immediate repair, 60-day, 6-month) if the operator justifies the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. An operator's justification for a deviation would be one of the records the operator is required to maintain for inspection. (See section 195.452(l).) An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure until a permanent repair is made. The operator would have to provide OPS 90-days notice by mail or facsimile.

What Preventive and Mitigative Measures Must an Operator Take To Protect the High Consequence Area? Section 195.452(i)

The final rule requires an operator to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. An operator must conduct a risk analysis of each pipeline segment to identify additional actions to enhance public safety or environmental protection. The rule lists some additional preventive or mitigative measures an operator needs to consider for the pipeline segment, including installing emergency flow restricting devices and modifying the leak detection systems. An operator is not limited to the listed measures but should also identify additional protective measures not listed.

The rule requires that, in identifying the need for additional preventive and mitigative measures, the operator evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. An operator must consider all relevant risk factors in making this determination; the rule lists some that an operator must consider. An operator is to supplement the listed risk factors with any other factors specific or unique to the pipeline segment. Listed factors include—terrain surrounding the pipeline, including drainage systems such as small streams and other smaller waterways that could act as a conduit to

the high consequence area; elevation profile; characteristics of the product transported; amount of product that could be released; possibility of a spillage in a farm field following the drain tile into a waterway; ditches along side a roadway the pipeline crosses; physical support of the pipeline segment such as by a cable suspension bridge; and exposure of the pipeline to operating pressure exceeding established maximum operating pressure. In addition, Appendix C to the rule provides an operator with further guidance on evaluating how each pipeline segment could affect a high consequence area.

Leak Detection

The final rule requires an operator to have some means to detect leaks on its pipeline system. The rule further requires an operator to evaluate the capability of its leak detection means and modify the capability, as necessary, to protect the high consequence area.

The rule lists factors that an operator must consider when making this evaluation. Again, the list is not exclusive. It is simply a starting point that an operator must supplement with factors relevant to each pipeline segment being evaluated.

Some examples of leak detection systems include—

Dynamic flow modeling: This model simulates the operating conditions of the pipeline through hydraulic calculations, then compares the computed pressures (based on flow rate, temperature, pipe profile, and density) against real time data obtained from various measuring points along the pipeline. Deviations are compared against alarm set points. When the deviations exceed the set points, the system alarms. These systems are normally integrated with the pipeline SCADA communications technology. Leak location information is not provided.

Tracer chemical: This approach requires mixing a very small amount (ppb to ppm of total volume) of a specific volatile chemical tracer with the contents of a pipeline. The chemical tracer is not a component of the pipeline contents and does not occur naturally in the soil. After the pipeline is inoculated with the tracer chemical, samples of the vapor contained in the soil outside the pipeline are collected. The soil vapor samples are obtained from probes or other devices installed intermittently along the pipeline. The vapor samples are analyzed by a gas chromatograph for the specific tracer chemical that was mixed with the pipeline contents. Presence of the tracer chemical in the

sample can only occur through an active release of pipeline product mixed with the tracer into the soil. These systems are able to provide single or continuous liquid tightness tests and will provide release location information.

Release Detection Cable: Release detection sensing cables are designed to alarm after contact with liquid hydrocarbons at any point along their length. The presence of hydrocarbons creates a circuit between two sensing wires and triggers an alarm. Typically, leak detection cable is installed in slotted PVC conduit that is buried in the pipe trench along or below the pipeline. These systems provide continuous monitoring via electronic control units capable of interfacing with SCADA technology and are able to provide leak location information.

Shut-in (static) released detection: This technique consists of a pressure test, with the pipeline filled with its normal contents. Between shipments, the pipeline is pressured against a closed valve(s). This release detection tool allows the operator to analyze the pipeline in a static (no flow) mode, without the complications of dynamic modeling. With the pipeline blocked, the pressure (compensated for temperature fluctuations) in a section should remain constant. The pressure is then monitored for any unexplained pressure losses. This test does not provide leak location information.

Pressure point analysis release detection software: Software for this system incorporates two independent methods of release detection: pressure point analysis and mass balance. Pattern recognition algorithms that distinguish normal operating events from leaks are used. With an appropriate communications system, this system can provide the calculated location of a release.

Emergency flow restricting devices (EFRDs)

The rule requires an operator to install an EFRD if the operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release. The rule lists certain factors that an operator must consider in making this determination, to be supplemented with other factors the operator determines are relevant to the pipeline segment being evaluated. Listed factors an operator must consider include the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for

ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline and the high consequence area, and benefits expected by reducing the spill size.

Installing an EFRD on a pipeline segment is only one of several possible preventive or mitigative measure that an operator can take to provide additional protection to a high consequence area.

What is a Process for Continual Evaluation and Assessment to Maintain a Pipeline's Integrity? Section 195.452(j)

The integrity assessment requirements do not stop with the baseline integrity assessment. An operator must continue to assess the integrity of the line pipe and evaluate the integrity of each pipeline segment that could affect a high consequence area. The rule requires an operator to conduct a periodic evaluation of each pipeline segment, as frequently as needed, to assure the pipeline's integrity. An operator would determine frequency based on specified risk factors plus other factors specific to the pipeline segment.

The evaluation is based, in part, on the information analysis the operator has made of the entire pipeline to determine what history and operations elsewhere could be relevant to the segment. The evaluation must also consider the past and present integrity assessment results, and decisions about repair, and preventive and mitigative actions. The evaluation must be done by a person qualified to evaluate the results and other related data.

As with the baseline assessment, the continual integrity assessment method must be by internal inspection, pressure test, or other technology that provides an equivalent understanding of the condition of the line pipe. As with the baseline assessment, if an operator chooses other technology as a re-assessment method, the operator must give 90-days advance notice (by mail or facsimile) to OPS.

An operator must conduct the integrity re-assessment at intervals not to exceed five years, except in those limited instances where the operator can clearly justify an extended interval. The rule requires that an operator base the continual assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals using specified risk factors (supplemented by risk factors relevant to the pipeline segment), the information analysis, and

analysis of the results from the last integrity assessment.

The rule recognizes limited exceptions to the five-year period.

- An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The operator must support the justification by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technologies. An operator would also have to demonstrate that the other technology would provide an understanding of the line pipe equivalent to that obtained by an assessment conducted at an interval of five years or less.

- The other exception is that an operator may not be able to conduct an integrity assessment on a segment of pipe within the required period because sophisticated internal inspection devices or other technology is not available. An operator must justify the reasons why it cannot comply with the required assessment period of not more than five years and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim.

In either instance, the operator must inform OPS of its proposed variance from intervals of not more than five years. A 90-day advance notice before the end of intervals of not more than five years is needed if the operator will require a longer assessment interval because sophisticated technology is not available. If the operator is justifying a longer assessment interval on an engineering basis, notice must be given nine months before the end of the interval of five years or less.

- The engineering-based exception has been included in the rule to encourage the use of advanced alternative technologies. It is intended for use in those instances where an operator is employing an advanced alternative technology and should therefore be dictated by the use of such technology. It is intended to be a limited exception to the interval of five years or less and not to exceed an additional two years whenever possible.

What Methods To Measure Program Effectiveness Must Be Used? Section 195.452(k)

The final rule requires that an operator include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. Because performance measures must be tailored to an individual

program, the rule does not specify the measures an operator has to include.

However, in the Appendix C to this rule we have provided guidance on performance measures. The guidance also gives examples of categories of performance measures that an operator should consider. Examples of measures that an operator could adapt for its program include—

- Selected Activity Measures—Measures that monitor the surveillance and preventive activities the operator has implemented.
- Deterioration Measures—Operation and Maintenance trends that indicate when the integrity of the system is weakening despite preventive measures.
- Failure Measures—Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.
- Internal vs. External Comparisons. Comparing data that could affect a high consequence area with data from pipeline segments in other areas of the system, and comparing data external to the pipeline segment.

What Records Must Be Kept? Section 195.452(l)

The final rule requires that an operator maintain certain records for inspection, including its written integrity management program. This requirement is not any different from the procedural manual an operator is required to maintain for operations, maintenance and emergencies. An operator would also be required to maintain for review during inspection documents that support the decisions and analyses made, and actions taken to implement and evaluate each element of the integrity management program. This would also include records documenting any modifications, justifications, variances, deviations and determinations made. Again, this requirement is no different from the myriad documents an operator now maintains to comply with the other provisions of the pipeline safety regulations.

The rule cannot possibly list all records that an operator would have to maintain to demonstrate its compliance with the integrity management program requirements. Appendix C provides examples of some documents that an operator would need to maintain for inspection. The list is not exhaustive. Listed examples include:

- Record identifying all pipeline segments that could affect a high consequence area;
- Baseline assessment plan that includes each required plan element;

- Modifications to the baseline assessment plan and reasons for the modifications;
- Use of and support for alternative practices;
- An integrity management program framework that includes each of the required program elements, updates and modifications to the initial framework and eventual program;
- Process for establishing the baseline and continual re-assessment intervals;
- Process for identifying population changes around a pipeline segment;
- Any variance from the required re-assessment intervals, and reasons for the deviation;
- Results of the baseline and continual integrity assessments;
- Results of the information analyses and periodic evaluations;
- Process for integrating and analyzing information about the integrity of a pipeline;
- Process and risk factors used for determining the frequency of periodic evaluations;
- Schedule for reviewing and analyzing integrity assessment results;
- Schedule for evaluating and repairing anomalies found during the integrity assessment;
- Any deviation from the required repair schedule for the listed conditions;
- Criteria for repair actions; records of anomalies detected actions taken to evaluate and repair the anomalies;
- Records of other remedial actions planned or taken;
- Risk analysis to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;
- Criteria and process for determining EFRD installation;
- Criteria and process for evaluating leak detection capability;
- Program performance measures.

Appendix C

We are adding a new Appendix C to Part 195. This Appendix gives guidance to help an operator implement the requirements of the integrity management program rule. An operator is not required to use this guidance. The Appendix contains guidance on—

- Information an operator may use to identify a high consequence area and factors an operator may use to consider the potential impacts of a release on a high consequence area;
- Risk factors an operator may use to determine an integrity assessment schedule;
- Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, an operator may use to determine if a

pipeline segment falls into a high, medium or low risk category.

- Types of internal inspection tools an operator may use to find pipeline anomalies;
- Measures an operator could use to measure an integrity management program's performance; and
- Types of records an operator will have to maintain.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

The Department of Transportation (DOT) considers this action to be a significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4, 1993). Therefore, it was forwarded to the Office of Management and Budget. This final rule is significant under DOT's regulatory policies and procedures (44 FR 11034; February 26, 1979).

Consideration of Public Comments

We received a number of comments that related to the draft Regulatory Evaluation that accompanied the proposed rule (65 FR 21695). OPS has considered those comments and has made changes in this evaluation where appropriate. Provided below is a summary of the comments and any changes made to the Regulatory Evaluation.

1. *Costs for Developing Integrity Management Programs.* Commenters suggested that the costs for developing integrity management programs were underestimated. The comments suggested that integrity management programs can cost \$75–\$300 thousand, rather than the \$25–\$75 thousand range used in the draft evaluation. OPS acknowledges that its estimate of the costs to prepare integrity management programs may have been too low. OPS has used the suggested range in this evaluation. OPS has continued to assume that 10 percent of the operators covered by the rule (those who own or operate 500 or more miles of hazardous liquid pipeline) will have already developed company-specific integrity management programs. Operators' costs to develop these programs have already been expended; operators will incur no further costs as a result of this rule. OPS has revised the estimated cost that will be incurred by the remaining 90 percent of covered operators for developing programs to \$100 thousand. (It is assumed that the programs operators develop that comply with the final rule will be less costly than the comprehensive programs that some operators have developed voluntarily.)

2. *Costs for Periodic Update and Documentation.* Commenters also suggested that the costs for periodic program updates and documentation (called "reports" in the draft evaluation) were underestimated. They estimated a range of \$50–150 thousand for this work. OPS agrees that the estimate in the draft evaluation was unrealistically low. In that evaluation, the only documentation considered was records of assessments, which were assumed to be produced by lower level personnel under general supervision. The draft evaluation failed to consider the need to evaluate whether changes to the program are needed, because technology or the pipeline changes or because high consequence areas are redrawn (as they will be periodically), and to make those changes. Operators will expend resources to evaluate these things, even if few changes are made. This will add costs. No update or changes will be required in some years, when the only expense will be to consider new information to ascertain whether an update is needed. OPS cannot accept, however, the presumption that the range of such annual costs will significantly overlap the range of costs to develop the programs in the first place, as suggested by the comment. Significantly less work is involved in updating an existing program. For purposes of this evaluation, OPS included the need to update an integrity management program. Costs for this effort were estimated at \$8,000 per year, which is considered reasonable compared to the estimated cost for developing the program initially. Routine documentation is estimated at \$2,000 annually, an increase of a factor of two from the estimate included in the draft evaluation. The net annual cost for updates and documentation is thus \$10,000 per operator or \$660 thousand in total.

OPS also included in this final evaluation costs for data integration. These costs will include a need to realign company-internal data management systems in the first year and continuing costs for the professional review of the integrated data related to the integrity of pipelines in high consequence areas. OPS has estimated costs for these activities at \$50,000 per operator in the first year after the rule (when internal data management realignment will occur) and \$25,000 per year thereafter.

3. *New Assessment will be Required.* Commenters disagreed with the assumption in the draft evaluation that no additional integrity assessment would be required, since operators were conducting internal inspection and

pressure testing at a rate sufficient to complete all required baseline assessment in the first seven years after the effective date of the rule. The total number of affected pipeline miles has also increased since the proposed rule. Because of these changes, OPS agrees that integrity assessment of the number of pipeline miles affected by the final rule will require an increase in the rate of assessment represented by recent industry practice. OPS continues to assume that initial assessment would have proceeded at the current rate if there were no rule. OPS has estimated costs for assessment that will be required above that rate to assure that all affected pipeline is assessed in the seven years following the effective date of the rule.

4. *Need for More Detailed Cost-benefit Analysis.* Commenters, including the Technical Hazardous Liquid Pipeline Safety Standards Committee (Advisory Committee), contended that the Regulatory Evaluation is not consistent with the OPS framework for cost-benefit analyses or in conformance with applicable standards. They suggested that OPS perform a more rigorous evaluation, perhaps in parallel with the rulemaking. They recommended that the suggested analysis quantify the benefits of the proposed rule, which was not done for the draft evaluation. The Advisory Committee unanimously voted that the Cost-Benefit Analysis was not sufficient. Commenters also cited failure to identify a specific target problem.

OPS has revised the regulatory evaluation to more closely follow the form of the framework. This included identifying the target problem. OPS agrees with the concerns of the Advisory Committee and other commenters but notes that it does not have adequate data on pipeline spills to accurately gauge the benefits of this rule. The DOT Inspector General, in its audit report, "Pipeline Safety Program Report No. RT-2000-069, March 12, 2000, stated, "OPS accident database contains inaccurate causal information and underestimates property damage." These problems make it difficult to prepare a more rigorous analysis. OPS has done some further research to examine the availability of additional data. OPS turned to data from the National Oceanographic and Atmospheric Administration (NOAA), the lead Federal Agency on quantifying the costs of hazardous liquid spills.

In their paper, *Putting Response and Natural Resource Damage Costs in Perspective*, Douglas Helton and Tony Penn, employees of NOAA, wrote that, "[t]he total private and social cost of oil spills is of great interest to industry,

responders, and regulators, but relatively few incidents have been examined in detail. Furthermore, publicly available cost data are often limited to State and Federal response costs and natural resource damages. Significant categories of costs, such as private response costs, third party claims, and vessel or facility repair costs, are often not publicly available." The authors further warn that, "[w]hen cost estimates are reported, they should be considered partial and spill volumes should be viewed with some skepticism." They conclude that, "[f]ailure to consider these additional cost categories because of unavailable data may result in erroneous conclusions regarding the total cost of spills and the significance of any one category."

Helton and Penn studied 48 spills between 1984 and 1997. (Note that most were not from pipelines.) Cost categories varied widely. Third party claims varied from less than 1% to more than 95% of total damages. Natural resource damages also varied from under 3% to 95%. Response costs also varied widely. The data set included 5 pipeline oil spills. The total known costs of the pipeline spills ranged from \$4.3 million to \$71.4 million.

The report concludes that, "[s]pills are costly events, and depending on the size and location of the spill may cost millions of dollars * * * The inability to account for all the costs of spills also has implications in other regulatory programs. Costs per unit spilled are often used in regulatory settings and the lack of complete data on the total costs of spills might result in inadequate liability limits."

OPS recognizes its data problems. To illustrate a few examples, the original estimate of the PEPSCO spill the operator provided was \$50,000 + of property damage. On further prodding the operator responded with supplemental reports raising costs to over \$50 million. Note that OPS reporting of accidents lumps together the categories of product lost, property damage and response costs, and environmental damage. This makes any kind of analysis extremely difficult.

A closer examination of OPS spill reports confirmed the DOT Inspector General's audit conclusion that OPS data collection concerning costs of oil spills is poor. The cause of this problem is two-fold.

(1) The need to collect improved data by requiring operators to report their data by category, for example to separately indicate cost of product loss, property damage to the operator, private parties, and to the public in terms of

natural resource damages. A more detailed listing of the costs of restoration and clean-up is necessary for better analysis, and

(2) Presently, accident reporting regulations require that operators report accident cost no later than 30 days from the incident occurrence. Supplemental reports are required thereafter when new information is available. Because of the complexity of some major oil spills, cleanup and restoration costs may not be known for several years after the spill. In a 1997 accident that OPS recently reexamined, the final costs have not been decided because the case is still under litigation.

Pipeline operators, as well as OPS, have not been diligent in requesting and providing supplemental reports. OPS will soon be taking corrective actions to ensure that timely and accurate supplemental reports are provided. In the absence of appropriate data OPS recognizes that it cannot appropriately determine the benefits of regulations which reduce the number of oil spills. However, as the data from NOAA indicate as well as the recent information from the PEPSCO spill, even the reported costs from oil spills represent a significant social cost to society. OPS regrets its data problems. However, as NOAA reports, OPS is not alone among Federal regulatory agencies in collecting insufficient spill data. OPS has recently proposed changes to its gas accident reporting. It will be proposing changes to its oil spill accident reporting requirements in the future.

However, the importance of this regulation in preventing the consequences of releases from hazardous liquid pipelines that could affect high consequence areas requires that OPS place this requirement on the industry in the absence of complete spill data. As stated in this evaluation, OPS concludes that the rule is justified based on the modest costs to implement and the subjective benefits of improving knowledge of pipe condition, addressing public concerns, and reducing the frequency and consequence of pipeline releases that affect high consequence areas. OPS concludes that this is adequate justification.

5. *The definition of high consequence areas should be expanded to include all national parks and fish hatcheries.* The Department of the Interior and the Environmental Protection Agency strongly recommended that the National Parks and National Fish Hatcheries be included as high consequence areas. We have not included these areas in the definition of high consequence areas. We will consider additional protection

for these areas, among others, in a future rulemaking.

The following section summarizes the final regulatory evaluation's findings.

Hazardous liquid pipeline spills can adversely affect human health and the environment. The magnitude of this impact differs. There are some areas in which the impact of a spill will be more significant than it would be in others due to concentrations of people who could be affected or to the presence of environmental resources that are unusually sensitive to damage. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. OPS is promulgating this regulation to afford the necessary additional protection to these high consequence areas.

Numerous investigations by OPS and the National Transportation Safety Board (NTSB) have highlighted the importance of protecting the public and environmentally sensitive areas from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated and environmentally sensitive areas. These recommendations included requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, determining hazards to public safety from electric resistance welded pipe and requiring installation of automatic or remotely-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipelines.

Congress also directed OPS to undertake additional safety measures in areas that are densely populated or unusually sensitive to environmental damage. These statutory requirements included having OPS prescribe standards for identifying pipelines in high density population areas, unusually sensitive environmental areas, and commercially navigable waters; issue standards requiring periodic inspections using internal inspection devices on pipelines in densely-populated and environmentally sensitive areas; and survey and assess the effectiveness of emergency flow restricting devices, and prescribe regulations on circumstances where an operator must use the devices.

This rulemaking addresses the target problem described above, and is a comprehensive response to NTSB's recommendations and Congressional mandates, as well as pipeline safety and environmental issues raised over the years.

This rule focuses on a systematic approach to integrity management to reduce the potential for hazardous liquid pipeline failures that could affect populated and unusually sensitive environmental areas, and commercially navigable waterways. This rulemaking requires pipeline operators to develop and follow an integrity management program that continually assesses, through internal inspection, pressure testing, or equivalent alternative technology, the integrity of those pipeline segments that could affect areas we have defined as high consequence areas i.e., populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. The program must also evaluate the segments through comprehensive information analysis, remediate integrity problems and provide additional protection through preventive and mitigative measures.

This final rule (the first in a series of integrity management program regulations) covers hazardous liquid pipeline operators that own or operate 500 or more miles of pipeline used in transportation. OPS intends to propose integrity management program requirements for the liquid operators not covered by this final rule and for natural gas transmission operators. OPS chose to start the series with this group of hazardous liquid operators because the pipelines they operate have the greatest potential to adversely affect the environment, based on the volume of product these pipelines transport. Further, by focusing first on these liquid operators, OPS is addressing requirements for an estimated 86.7 percent of hazardous liquid pipelines. It is estimated that approximately 35.5 thousand miles (of the 157,000 miles of hazardous liquid pipeline in the U.S.) will be impacted by this final rule.

We have estimated the cost to develop the necessary program at approximately \$5.94 million, with an additional annual cost for program upkeep and reporting of \$660,000. An operator's program begins with a baseline assessment plan and a framework that addresses each required program element. The framework indicates how decisions will initially be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be continually updated and improved.

The rule requires a baseline assessment of covered pipeline segments through internal inspection, pressure test, or use of other technology capable of comparable performance. The baseline assessment must be completed

within seven years after the final rule becomes effective. After this baseline assessment, an operator is further required to periodically re-assess and evaluate the pipeline segment to ensure its integrity. It is estimated that the cost of periodic reassessment will generally not occur until the sixth year unless the baseline assessment indicates significant defects that would require earlier reassessment. Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred in realigning existing data systems to permit integration and in analysis of the integrated data by knowledgeable pipeline safety professionals. The total costs for the information integration requirements in this rule are \$2.95 million in the first year and \$1.5 million annually thereafter.

The rule requires operators to identify additional preventive or mitigative measures that would enhance public safety or environmental protection based on a risk analysis of the pipeline segment. One of the many preventive or mitigative actions an operator may take is to install an EFRD on the pipeline segment. OPS could not estimate the total cost of installing EFRDs because OPS does not know how many operators will install them. Additionally, requirements have been added for an operator to evaluate its leak detection capability and modify that capability, if necessary. OPS does not know how many operators currently have leak detection systems or how many will be installed or upgraded as a result of this rule. OPS was therefore also unable to estimate the total costs of the leak detection requirements.

Affected operators will be required to assess more line pipe in segments that could affect high consequence areas as a result of this rule than they would have been expected to assess if the rule had not been issued. Integrity assessment consists of a baseline assessment, to be conducted over the first seven years after the effective date of the rule, and subsequent re-assessment at intervals not to exceed every five years.

OPS has estimated the annual cost of additional baseline assessment that will be required by this rule as \$9.95 million. The cost for additional re-assessment that will be required to meet the five-year re-assessment requirement is \$17 million per year. Cost impact will be greater in the sixth and seventh years after the effective date of the rule due to an overlap between baseline inspection and the initial subsequent testing. The

additional costs in these two years are estimated at \$38.2 million.

The benefits of this rule can not easily be quantified but can be described in qualitative terms. Issuance of this final rule ensures that all operators will perform at least to a baseline safety level and will contribute to an overall higher level of safety and environmental performance nationwide. It will lead to greater uniformity in how risk is evaluated and addressed and will provide more clarity in discussion by government, industry and the public about safety and environmental concerns and how they can be resolved.

Much of the final rule is written in performance-based language. A performance-based approach provides several advantages: encouraging development and use of new technologies; supporting operators' development of more formal, structured risk evaluation programs and OPS's evaluation of the programs; and providing greater ability for operators to customize their long-term maintenance programs.

The rule has also stimulated the pipeline industry to begin developing a supplemental consensus standard to support risk-based approaches to integrity management. The rule has further fostered development of industry-wide technical standards, such as repair criteria to use following an internal inspection.

Our emphasis on an integrity-based approach encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. This orientation will lead to addressing the most significant risks in populated areas, unusually sensitive environmental areas, and commercially navigable waterways. Commercially navigable waterways are included because of their importance as a supply route of vital resources to many American communities as well as their role in the national defense system. This integrity-based approach is the best opportunity to improve industry performance and assure that these high consequence areas get the protection they need. It also addresses the interrelationships among failure causes and benefits the coordination of risk control actions, beyond what a solely compliance-based approach would achieve.

The final rule provides for a verification process, which gives the regulator a better opportunity to influence the methods of assessment and the interpretation of results. OPS will provide a beneficial challenge to

the adequacy of an operator's decision process. Requiring operators to use the integrity management process, and having regulators validate the adequacy and implementation of this process, should expedite the operators' rates of remedial action, thereby strengthening the pipeline system and reducing the public's exposure to risk.

A particularly significant benefit is the quality of information that will be gathered as a result of this proposal to aid operators' decisions about providing additional protections. Two essential elements of the integrity management program are that an operator continually assess and evaluate the pipeline's integrity, and perform an analysis that integrates all available information about the pipeline's integrity. The process of planning, assessment and evaluation will provide operators with better data on which to judge a pipeline's condition and the location of potential problems that must be addressed.

Integrating this data with the environmental and safety concerns associated with high consequence areas will help prompt operators and the Federal and state governments to focus time and resources on potential risks and consequences that require greater scrutiny and the need for more intensive preventive and mitigation measures. If baseline and periodic assessment data is not evaluated in the proper context, it is of little or no value. It is imperative that the information an operator gathers is assessed in a systematic way as part of the operator's ongoing examination of all threats to the pipeline integrity. The rule is intended to accomplish that.

The public has expressed concern about the danger hazardous liquid pipelines pose to their neighborhoods. The integrity management process leads to greater accountability to the public for both the operator and the regulator. This accountability is enhanced through our choice of a map-based approach to defining the areas most in need of additional protection—the visual depiction of the populated areas, unusually sensitive environmental areas, and commercially navigable waterways in need of protection focuses on the safety and environmental issues in a manner that will be easily understandable to everyone. The system integrity requirements and the sharing of information about their implementation and effectiveness will assure the public that operators are continually inspecting and evaluating the threats to pipelines that pass through or close to populated areas to better ensure that the pipelines are safe.

OPS has not provided quantitative benefits for the continual integrity management evaluation required in this final rule. OPS does not believe, however, that requiring this comprehensive process, including the re-assessment of pipelines in high consequence areas at a minimum of once every five years, will be an undue burden on hazardous liquid operators covered by this proposal. OPS believes the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in populated and important environmental areas and commercially navigable waterways, is benefit enough to promulgate these requirements.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). OPS must consider whether a rulemaking would have a significant impact on a substantial number of small entities. This rulemaking was designed to impact only those hazardous liquid operators that own or operate 500 or more miles of pipeline. Because of this limitation on pipeline mileage, only 66 hazardous liquid pipeline operators (large national energy companies) covering 86.7 percent of regulated liquid transmission lines are impacted by this final rule. Based on this, and the evidence discussed above, I certify that this final rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), the Department of Transportation has submitted a copy of the Paperwork Reduction Act Analysis to the Office of Management and Budget for its review. The name of the information collection is "Pipeline Integrity Management in High Consequence Areas." The purpose of this information collection is designed to require operators of hazardous liquid pipelines to develop a program to provide direct integrity testing and evaluation of hazardous liquid pipelines in high consequence areas.

Several commenters (pipeline operators and trade associations), suggested that OPS underestimated the time and cost to develop the necessary program as well as the time and costs to revise the program. OPS concurs with these comments and has revised the costs burden hours as shown below.

Sixty-six hazardous liquid operators will be subject to this final rule. It is estimated that 59 of these operators will

have to develop integrity management programs taking approximately 2800 hours per program. (Ten percent of hazardous liquid operators are estimated to already have sufficient programs to comply with the rule.) Each of the 59 operators would also have to devote 1,000 in the first year to integrate this data into current management information systems.

Additionally, all 66 operators will be required to update their programs on a continual basis. This will take approximately 330 hours per program annually. An additional 500 hours per operator (for the 90% of operators who do not have a program or whose program does not comply with the rule) will be required to annually integrate the data into the operator's current management information systems.

Operators are required to either use hydrostatic testing or smart pigging as a method to assess their pipelines. However, operators can use another technology if it can demonstrate it provides an equivalent understanding of the condition of the line pipe as the other two assessment methods. Operators have to provide OPS 90-days notice (by mail or facsimile) before using the other technology. OPS believes that few operators will choose this option. If they do choose an alternate technology, notice preparation should take approximately one hour. Because OPS believes few if any operators will elect to use other technologies, the burden was considered minimal and therefore not calculated.

Additionally, operators could seek a variance in limited situations from the required five-year continual re-assessment interval if they can provide the necessary justification and supporting documentation. Notice would have to be provided to OPS when an operator seeks a variance. OPS believes that approximately 10% of operators may request a variance. This is approximately 7 operators. The advance notification can be in the form of letter or fax. OPS believes the burden of a letter or fax is minimal and therefore did not add it to the overall burden hours discussed above.

Organizations and individuals desiring to submit comments on the information collection should direct them to the Office of Information and Regulatory Affairs, OMB, Room 10235, New Executive Office Building, Washington, D.C. 20503; Attention Desk Officer for the Department of Transportation. Comments must be sent within 30 days of the publication of this final rule.

The Office of Management and Budget is specifically interested in the following issues concerning the information collection:

- Evaluating whether the collection is necessary for the proper performance of the functions of the Department, including whether the information would have a practical use;
- Evaluating the accuracy of the Department's estimate of the burden of the collection of information, including the validity of assumptions used;
- Enhancing the quality, usefulness and clarity of the information to be collected; and minimizing the burden of collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology; e.g., permitting electronic submission of responses.

According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. The valid OMB control number for this information collection will be published in the **Federal Register** after it is approved by the OMB. For more details, see the Paperwork Reduction Analysis available for copying and review in the public docket.

Executive Order 13084

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13084 ("Consultation and Coordination with Indian Tribal Governments"). Because this final rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 ("Federalism"). This final rule does not adopt any regulation that:

- (1) Has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government;
- (2) Imposes substantial direct compliance costs on States and local governments; or
- (3) Preempts state law.

Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10,

1999) do not apply. Nevertheless, in a November 18–19, 1999 public meeting, OPS invited National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Again in January, and February 2000, OPS held conference calls with NAPSR, to receive their input before proposing an integrity management rule.

Unfunded Mandates

This rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of \$100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rule.

National Environmental Policy Act

We have analyzed the final rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. Section 4332), the Council on Environmental Quality regulations (40 CFR Sections 1500–1508), and DOT Order 5610.1D, and have determined that this action would not significantly affect the quality of the human environment. We updated the Environmental Assessment that supported the proposed rule (65 FR 21695) to reflect the provisions of the final rule.

The final Environmental Assessment determined that the combined impacts of the initial baseline assessment (pressure testing or internal inspection), the subsequent periodic assessments, and additional preventive and mitigative measures that may be implemented to protect high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures in and near high consequence areas are likely to be reduced. However, from a national perspective, the impact is not expected to be significant for the pipeline operators covered by the final rule. The following discussion summarizes the analysis provided in the final Environmental Assessment.

Many operators covered by the final rule already have internal inspection and testing programs. These operators typically place a high priority on the pipeline's proximity to populated areas, recreation and conservation areas, and environmental resources when making decisions about where and when to inspect and test pipelines. As a result, pipelines that could affect some of the defined high consequence areas have

already been recently assessed, and a sizeable fraction of pipelines in the remaining locations would likely have been assessed in the next several years, without the provisions of the rule. The primary effect of the rule—accelerating integrity assessment of pipeline segments that could affect some high consequence areas—only shifts the improved integrity assurance forward for a few years for most high consequence areas. Because pipeline failure rates are low, shifting the time at which these segments are assessed forward by a few years, has only a small effect on the likelihood of pipeline failures in or near high consequence areas.

Neither internal inspection nor pressure testing protect against all threats to pipeline integrity. Specifically, they do not prevent outside force damage, the most significant contributor to hazardous liquid pipeline failures. However, the rule does require operators to conduct an integrated analysis and evaluation of all the potential threats to pipeline integrity, and to consider additional preventive or mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause—like third party damage—these evaluations should result in additional risk controls to address these threats. However, without knowing the specific high consequence area locations, the specific risks present at these locations, and the existing operator risk controls (including those that surpass the current minimum regulatory requirements), it is difficult to determine the impact of this requirement.

A number of liquid operators covered by the rule already perform integrity evaluations or formal risk assessments that consider the impacts of pipeline system failures on the environment and population in proximity to their lines. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. Thus, it is expected that additional risk controls resulting from the integrated evaluation will be limited with most new actions customized to address site-specific integrity issues that the operator may not have previously recognized. For many high consequence areas, it is probable that operators will determine the existing preventive and mitigative activities provide adequate protection, and that the small risk reduction benefits of additional risk controls are not justified.

The primary benefits of the final rule will be to establish requirements for conducting integrity assessments and periodic evaluations of the pipeline

segments that could affect high consequence areas. In effect, this will establish uniform integrity management programs across the pipeline industry and enhance the integrity assessment activities many operators are currently implementing. It will also require operators who have minimal, or no, integrity assessment and evaluation programs to raise their level of performance. Thus, the rule is expected to ensure a more consistent, and overall higher level of integrity assurance for high consequence areas across the industry.

In accordance with 40 CFR Section 1508.13, based on the updated Environmental Assessment, and no receipt of comment or information showing otherwise, we have prepared a Finding of No Significant Impact (FONSI) for this final rule. The updated Environmental Assessment and the Finding of No Significant Impact are available for review in the docket.

List of Subjects in 49 CFR Part 195

Carbon dioxide, High consequence areas, Integrity assurance, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, OPS is amending part 195 of title 49 of the Code of Federal Regulations as follows:

PART 195—[AMENDED]

1. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

Subpart F—Operation and Maintenance

2. New §§ 195.450 and 195.452 are added under new undesignated centerheadings of “High Consequence Areas” and “Pipeline Integrity Management”, respectively, to subpart F to read as follows:

High Consequence Areas

195.450 Definitions.

Pipeline Integrity Management

195.452 Pipeline integrity management in high consequence areas.

High Consequence Areas

§ 195.450 Definitions.

The following definitions apply to this section and § 195.452:

Emergency flow restricting device or *EFRD* means a check valve or remote control valve as follows:

(1) *Check valve* means a valve that permits fluid to flow freely in one direction and contains a mechanism to

automatically prevent flow in the other direction.

(2) *Remote control valve* or RCV means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

High consequence area means:

(1) A *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists;

(2) A *high population area*, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;

(3) An *other populated area*, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;

(4) An *unusually sensitive area*, as defined in § 195.6.

Pipeline Integrity Management

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which operators must comply?* This section applies to each operator who owns or operates a total of 500 or more miles of hazardous liquid pipeline subject to this part.

(b) *What must an operator do?* (1) No later than March 31, 2002, an operator must develop a written integrity management program that addresses the risks on each pipeline segment that could affect a high consequence area. An operator must include in the program:

(i) An identification of all pipeline segments that could affect a high consequence area. A pipeline segment in a high consequence area is presumed to affect that area unless the operator's risk assessment effectively demonstrates otherwise. (See Appendix C of this part for guidance on identifying pipeline segments.) An operator must complete this identification no later than December 31, 2001;

(ii) A plan for baseline assessment of the line pipe (see paragraph (c) of this section);

(iii) A framework addressing each element of the integrity management program, including continual integrity assessment and evaluation (see

paragraphs (f) and (j) of this section). The framework must initially indicate how decisions will be made to implement each element.

(2) An operator must implement and follow the program it develops.

(3) In carrying out this section, an operator must follow recognized industry practices unless the section specifies otherwise or the operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

(c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan:

(i) The methods selected to assess the integrity of the line pipe. For low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies. An operator must assess the integrity of the line pipe by:

(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(B) Pressure test conducted in accordance with subpart E of this part; or

(C) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address specified in § 195.58 or to the facsimile number specified in § 195.56;

(ii) A schedule for completing the integrity assessment;

(iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

(2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.

(d) *When must the baseline assessment be completed?* (1) *Time period.* An operator must establish a baseline assessment schedule to determine the priority for assessing the pipeline segments. An operator must complete the baseline assessment by March 31, 2008. An operator must assess at least 50% of the line pipe subject to the requirements of this section, beginning with the highest risk pipe, by September 30, 2004.

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section, an operator may use an integrity assessment conducted after January 1, 1996, if the integrity assessment method meets the requirements of this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must re-assess the line pipe according to the requirements of paragraph (j)(3) of this section.

(3) *Newly-identified areas.* (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in § 195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(ii) An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:

(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.

(2) Appendix C of this part provides further guidance on risk factors.

(f) *What are the elements of an integrity management program?* An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:

(1) A process for identifying which pipeline segments could affect a high consequence area;

(2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

(4) Criteria for repair actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

(7) Methods to measure the program's effectiveness (see paragraph (k) of this section);

(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:

(1) 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;

(2) Data gathered through the integrity assessment required under this section;

(3) Data gathered in conjunction with other inspections, tests, surveillance

and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and

(4) Information about how a failure would affect the high consequence area, such as location of the water intake.

(h) *What actions must be taken to address integrity issues?* (1) *General requirements.* An operator must take prompt action to address all pipeline integrity issues raised by the assessment and information analysis. An operator must evaluate all anomalies and repair those anomalies that could reduce a pipeline's integrity. An operator must comply with § 195.422 in making a repair.

(2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine the need for repair. Depending on circumstances, an operator may have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly, or when an operator receives the final internal inspection report. The date of discovery can be no later than the date of the integrity assessment results or the final report.

(3) *Review of integrity assessment.* An operator must include in its schedule for evaluation and repair (as required by paragraph (h)(4) of this section), a schedule for promptly reviewing and analyzing the integrity assessment results. After March 31, 2004, an operator's schedule must provide for review of the integrity assessment results within 120 days of conducting each assessment. The operator must obtain and assess a final report within an additional 90 days.

(4) *Schedule for repairs.* An operator must complete repairs according to a schedule that prioritizes the conditions for evaluation and repair. An operator must base the schedule on the risk factors listed in paragraph (e)(1) of this section and any pipeline-specific risk factors the operator develops. If an operator cannot meet the schedule for any of the conditions addressed in paragraphs (h)(5)(i) through (iv) of this section, the operator must justify the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure until a permanent repair is made. An operator must send a notice to the address specified in

§ 195.58 or to the facsimile number specified in § 195.56.

(5) *Special requirements for scheduling repairs—(i) Immediate repair conditions.* An operator's evaluation and repair schedule must provide for immediate repair conditions. To maintain safety, an operator will need to temporarily reduce operating pressure or shut down the pipeline until the operator can complete the repair of these conditions. An operator must base the temporary operating pressure reduction on remaining wall thickness. An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss greater than 80% of nominal wall regardless of dimensions.

(B) Predicted burst pressure less than the maximum operating pressure at the location of the anomaly. Burst pressure has been calculated from the remaining strength of the pipe, using a suitable metal loss strength calculation, e.g., ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991)) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are available at the addresses listed at § 195.3.

(C) Dents on the top of the pipeline (above 4 and 8 o'clock position) with any indicated metal loss.

(D) Significant anomaly that in the judgment of the person evaluating the assessment results requires immediate action.

(ii) *60-day conditions.* Except for conditions listed in paragraph (h)(5)(i) of this section, an operator must schedule for evaluation and repair all dents, regardless of size, located on the top of the pipeline (above 4 and 8 o'clock position) within 60 days of discovery of the condition.

(iii) *Six-month conditions.* Except for conditions listed in paragraph (h)(5)(i) or (ii) of this section, an operator must schedule evaluation and repair of the following within six months of discovery of the condition:

(A) Dents with metal loss or dents that affect pipe curvature at a girth or seam weld.

(B) Dents with reported depths greater than 6% of the pipe diameter.

(C) Remaining strength of the pipe results in a safe operating pressure that is less than the current established MOP at the location of the anomaly using a suitable safe operating pressure calculation method (e.g., ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991)) or AGA Pipeline

Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are available at the addresses listed at § 195.3.

(D) Areas of general corrosion with a predicted metal loss of >50% of nominal wall.

(E) Predicted metal loss of >50% of nominal wall at crossings of another pipeline.

(F) Weld anomalies with a predicted metal loss >50% of nominal wall.

(G) Potential crack indications that when excavated are determined to be cracks.

(H) Corrosion of or along seam welds.

(I) Gouges or grooves greater than 12.5% of nominal wall.

(iv) *Other conditions.* An operator must schedule evaluation and repair of the following conditions:

(A) Data that reflect a change since last assessed.

(B) Data that indicate mechanical damage that is located on the top half of the pipe.

(C) Data that indicate anomalies abrupt in nature.

(D) Data that indicate anomalies longitudinal in orientation.

(E) Data that indicate anomalies over a large area.

(F) Anomalies located in or near casings, crossings of another pipeline, and areas with suspect cathodic protection.

(i) *What preventive and mitigative measures must an operator take to protect the high consequence area? (1) General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high

consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;

(ii) Elevation profile;

(iii) Characteristics of the product transported;

(iv) Amount of product that could be released;

(v) Possibility of a spillage in a farm field following the drain tile into a waterway;

(vi) Ditches along side a roadway the pipeline crosses;

(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

(3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors—length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

(4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors—the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

(j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity? (1) General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the

integrity of each pipeline segment that could affect a high consequence area.

(2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the past and present integrity assessment results, information analysis (paragraph (g) of this section), and decisions about repair, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) *Assessment intervals.* An operator must establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

(4) *Variance from the 5-year intervals in limited situations—(i) Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which is obtainable under paragraph (j)(2) of this section. An operator must notify OPS nine months before the end of the intervals of five years or less of the reason why the operator intends to justify a longer interval. An operator must send a notice to the address specified in § 195.58 or to the facsimile number specified in § 195.56. The notice must state a proposed alternative interval.

(ii) *Unavailable technology.* An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the intervals of five years or less that the operator may require a longer assessment interval. An operator must

send a notice to the address specified in § 195.58 or to the facsimile number specified in § 195.56. The Operator may have up to an additional 180 days to complete the assessment.

(5) *Assessment methods.* An operator must assess the integrity of the line pipe by:

(i) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(ii) Pressure test conducted in accordance with subpart E of this part; or

(iii) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 60 days before conducting the assessment, by sending a notice to the address specified in § 195.58 or to the facsimile number specified in § 195.56.

(6) However, for low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

(l) *What records must be kept?* An operator must maintain for review during an inspection:

(i) A written integrity management program in accordance with paragraph (b) of this section.

(ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

(2) See Appendix C of this part for examples of records an operator would be required to keep.

3. A new Appendix C is added to part 195 to read as follows:

Appendix C to Part 195—Guidance for Implementation of Integrity Management Program

This Appendix gives guidance to help an operator implement the requirements of the integrity management program rule in §§ 195.450 and 195.452. Guidance is provided on:

(1) Information an operator may use to identify a high consequence area and factors an operator can use to consider the potential impacts of a release on an area;

(2) Risk factors an operator can use to determine an integrity assessment schedule;

(3) Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, an operator may use to determine if a pipeline segment falls into a high, medium or low risk category;

(4) Types of internal inspection tools an operator could use to find pipeline anomalies;

(5) Measures an operator could use to measure an integrity management program's performance; and

(6) Types of records an operator will have to maintain.

I. Identifying a high consequence area and factors for considering a pipeline segment's potential impact on a high consequence area.

A. The rule defines a High Consequence Area as a high population area, an other populated area, an unusually sensitive area, or a commercially navigable waterway. The Office of Pipeline Safety (OPS) will map these areas on the National Pipeline Mapping System (NPMS). An operator, member of the public, or other government agency may view and download the data from the NPMS home page <http://www.npms.rspa.dot.gov>. OPS will maintain the NPMS and update it periodically. However, it is an operator's responsibility to ensure that it has identified all high consequence areas that could be affected by a pipeline segment. An operator is also responsible for periodically evaluating its pipeline segments to look for population or environmental changes that may have occurred around the pipeline and to keep its program current with this information. (Refer to § 195.452(d)(3).) For more information to help in identifying high consequence areas, an operator may refer to:

(1) Digital Data on populated areas available on U.S. Census Bureau maps.

(2) Geographic Database on the commercial navigable waterways available on <http://www.bts.gov/gis/ntatlas/networks.html>.

(3) The Bureau of Transportation Statistics database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website at <http://www.bts.gov/gis/ntatlas/networks.html>.

B. The rule requires an operator to include a process in its program for identifying which pipeline segments could affect a high consequence area and to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. (See §§ 195.452 (f) and (i).) Thus, an operator will need to consider how each pipeline segment could affect a high consequence area. The primary source for the listed risk factors is a US DOT study on instrumented Internal Inspection devices (November 1992). Other sources include the National Transportation Safety Board, the Environmental Protection Agency and the Technical Hazardous Liquid Pipeline Safety Standards Committee. The following list provides guidance to an operator on both the mandatory and additional factors:

(1) Terrain surrounding the pipeline. An operator should consider the contour of the

land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps.

(2) Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.

(3) Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway.

(4) Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.

(5) The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids becomes gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.

(6) Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.

(7) Operating condition of pipeline (pressure, flow rate, etc.) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

(8) The hydraulic gradient of pipeline.

(9) The diameter of pipeline, the potential release volume, and the distance between the isolation points.

(10) Potential physical pathways between the pipeline and the high consequence area.

(11) Response capability (time to respond, nature of response).

(12) Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

II. Risk factors for establishing frequency of assessment.

A. By assigning weights or values to the risk factors, and using the risk indicator tables, an operator can determine the priority for assessing pipeline segments, beginning with those segments that are of highest risk, that have not previously been assessed. This list provides some guidance on some of the risk factors to consider (see § 195.452(e)). An operator should also develop factors specific to each pipeline segment it is assessing, including:

(1) Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.

(2) Results from previous testing/inspection. (See § 195.452(h).)

(3) Leak History. (See leak history risk table.)

(4) Known corrosion or condition of pipeline. (See § 195.452(g).)

(5) Cathodic protection history.

(6) Type and quality of pipe coating (disbonded coating results in corrosion).

(7) Age of pipe (older pipe shows more corrosion—may be uncoated or have an ineffective coating) and type of pipe seam. (See Age of Pipe risk table.)

(8) Product transported (highly volatile, highly flammable and toxic liquids present a

greater threat for both people and the environment) (see Product transported risk table.)

(9) Pipe wall thickness (thicker walls give a better safety margin)

(10) Size of pipe (higher volume release if the pipe ruptures).

(11) Location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic (permafrost causes settlement—Alaska); geologic (landslides or subsidence).

(12) Security of throughput (effects on customers if there is failure requiring shutdown).

(13) Time since the last internal inspection/pressure testing.

(14) With respect to previously discovered defects/anomalies, the type, growth rate, and size.

(15) Operating stress levels in the pipeline.

(16) Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).

(17) Physical support of the segment such as by a cable suspension bridge.

(18) Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).

B. *Example:* This example illustrates a hypothetical model used to establish an integrity assessment schedule for a hypothetical pipeline segment. After we determine the risk factors applicable to the pipeline segment, we then assign values or numbers to each factor, such as, high (5), moderate (3), or low (1). We can determine an overall risk classification (A, B, C) for the segment using the risk tables and a sliding scale (values 5 to 1) for risk factors for which tables are not provided. We would classify a segment as C if it fell above 2/3 of maximum value (highest overall risk value for any one segment when compared with other segments of a pipeline), a segment as B if it fell between 1/3 to 2/3 of maximum value, and the remaining segments as A.

i. For the baseline assessment schedule, we would plan to assess 50% of all pipeline

segments covered by the rule, beginning with the highest risk segments, within the first 3 1/2 years and the remaining segments within the seven-year period. For the continuing integrity assessments, we would plan to assess the C segments within the first two (2) years of the schedule, the segments classified as moderate risk no later than year three or four and the remaining lowest risk segments no later than year five (5).

ii. For our hypothetical pipeline segment, we have chosen the following risk factors and obtained risk factor values from the appropriate table. The values assigned to the risk factors are for illustration only.

Age of pipeline: assume 30 years old (refer to "Age of Pipeline" risk table)—

Risk Value=5

Pressure tested: tested once during construction—

Risk Value=5

Coated: (yes/no)—yes

Coating Condition: Recent excavation of suspected areas showed holidays in coating (potential corrosion risk)—

Risk Value=5

Cathodically Protected: (yes/no)—yes—Risk Value=1

Date cathodic protection installed: five years after pipeline was constructed (Cathodic protection installed within one year of the pipeline's construction is generally considered low risk.)—Risk Value=3

Close interval survey: (yes/no)—no—Risk Value =5

Internal Inspection tool used: (yes/no)—yes.

Date of pig run? In last five years—Risk Value=1

Anomalies found: (yes/no)—yes, but do not pose an immediate safety risk or environmental hazard—Risk Value=3

Leak History: yes, one spill in last 10 years. (refer to "Leak History" risk table)—Risk Value=2

Product transported: Diesel fuel. Product low risk. (refer to "Product" risk table)—Risk Value=1

Pipe size: 16 inches. Size presents moderate risk (refer to "Line Size" risk table)—Risk Value=3

iii. Overall risk value for this hypothetical segment of pipe is 34. Assume we have two other pipeline segments for which we

conduct similar risk rankings. The second pipeline segment has an overall risk value of 20, and the third segment, 11. For the baseline assessment we would establish a schedule where we assess the first segment (highest risk segment) within two years, the second segment within five years and the third segment within seven years. Similarly, for the continuing integrity assessment, we could establish an assessment schedule where we assess the highest risk segment no later than the second year, the second segment no later than the third year, and the third segment no later than the fifth year.

III. Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported.

LEAK HISTORY

| Safety risk indicator | Leak history (Time-dependent defects) ¹ |
|-----------------------|--|
| High | > 3 Spills in last 10 years |
| Low | < 3 Spills in last 10 years |

¹ Time-dependent defects are those that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

LINE SIZE OR VOLUME TRANSPORTED

| Safety risk indicator | Line size |
|-----------------------|---------------------------|
| High | ≥ 18" |
| Moderate | 10"—16" nominal diameters |
| Low | ≤ 8" nominal diameter |

AGE OF PIPELINE

| Safety risk indicator | Age Pipeline condition dependent) ¹ |
|-----------------------|--|
| High | > 25 years |
| Low | < 25 years |

¹ Depends on pipeline's coating & corrosion condition, and steel quality, toughness, welding.

PRODUCT TRANSPORTED

| Safety risk indicator | Considerations ¹ | Product examples |
|-----------------------|---------------------------------------|---|
| High | (Highly volatile and flammable) | (Propane, butane, Natural Gas Liquid (NGL), ammonia). |
| Medium | Highly toxic | (Benzene, high Hydrogen Sulfide content crude oils). |
| Low | Flammable—flashpoint <100F | (Gasoline, JP4, low flashpoint crude oils). |
| | Non-flammable—flashpoint 100+F | (Diesel, fuel oil, kerosene, JP5, most crude oils). |

¹ The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values may be used as an indication of chronic toxicity. National Fire Protection Association health factors may be used for rating acute hazards.

IV. Types of internal inspection tools to use.

An operator should consider at least two types of internal inspection tools for the integrity assessment from the following list. The type of tool or tools an operator selects will depend on the results from previous

internal inspection runs, information analysis and risk factors specific to the pipeline segment:

(1) Geometry Internal inspection tools for detecting changes to ovality, e.g., bends, dents, buckles or wrinkles, due to

construction flaws or soil movement, or other outside force damage;

(2) Metal Loss Tools (Ultrasonic and Magnetic Flux Leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion.

(3) Crack Detection Tools for detecting cracks and crack-like features, e.g., stress corrosion cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks, etc.

V. Methods to measure performance.

A. *General.* (1) This guidance is to help an operator establish measures to evaluate the effectiveness of its integrity management program. The performance measures required will depend on the details of each integrity management program and will be based on an understanding and analysis of the failure mechanisms or threats to integrity of each pipeline segment.

(2) An operator should select a set of measurements to judge how well its program is performing. An operator's objectives for its program are to ensure public safety, prevent or minimize leaks and spills and prevent property and environmental damage. A typical integrity management program will be an ongoing program and it may contain many elements. Therefore, several performance measure are likely to be needed to measure the effectiveness of an ongoing program.

B. *Performance measures.* These measures show how a program to control risk on pipeline segments that could affect a high consequence area is progressing under the integrity management requirements. Performance measures generally fall into three categories:

(1) *Selected Activity Measures*—Measures that monitor the surveillance and preventive activities the operator has implemented. These measure indicate how well an operator is implementing the various elements of its integrity management program.

(2) *Deterioration Measures*—Operation and maintenance trends that indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities.

(3) *Failure Measures*—Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.

C. *Internal vs. External Comparisons.* These comparisons show how a pipeline segment that could affect a high consequence area is progressing in comparison to the operator's other pipeline segments that are not covered by the integrity management requirements and how that pipeline segment compares to other operators' pipeline segments.

(1) *Internal*—Comparing data from the pipeline segment that could affect the high consequence area with data from pipeline segments in other areas of the system may indicate the effects from the attention given to the high consequence area.

(2) *External*—Comparing data external to the pipeline segment (e.g., OPS incident data) may provide measures on the frequency and size of leaks in relation to other companies.

D. *Examples.* Some examples of performance measures an operator could use include—

(1) A performance measurement goal to reduce the total volume from unintended releases by -% (percent to be determined by operator) with an ultimate goal of zero.

(2) A performance measurement goal to reduce the total number of unintended releases (based on a threshold of 5 gallons) by ____-% (percent to be determined by operator) with an ultimate goal of zero.

(3) A performance measurement goal to document the percentage of integrity management activities completed during the calendar year.

(4) A performance measurement goal to track and evaluate the effectiveness of the operator's community outreach activities.

(5) A narrative description of pipeline system integrity, including a summary of performance improvements, both qualitative and quantitative, to an operator's integrity management program prepared periodically.

(6) A performance measure based on internal audits of the operator's pipeline system per 49 CFR Part 195.

(7) A performance measure based on external audits of the operator's pipeline system per 49 CFR Part 195.

(8) A performance measure based on operational events (for example: relief occurrences, unplanned valve closure, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity.

(9) A performance measure to demonstrate that the operator's integrity management program reduces risk over time with a focus on high risk items.

(10) A performance measure to demonstrate that the operator's integrity management program for pipeline stations and terminals reduces risk over time with a focus on high risk items.

VI. Examples of types of records an operator must maintain.

The rule requires an operator to maintain certain records. (See § 195.452(l)). This section provides examples of some records that an operator would have to maintain for inspection to comply with the requirement. This is not an exhaustive list.

(1) a process for identifying which pipelines could affect a high consequence area and a document identifying all pipeline segments that could affect a high consequence area;

(2) a plan for baseline assessment of the line pipe that includes each required plan element;

(3) modifications to the baseline plan and reasons for the modification;

(4) use of and support for an alternative practice;

(5) a framework addressing each required element of the integrity management program, updates and changes to the initial framework and eventual program;

(6) a process for identifying a new high consequence area and incorporating it into the baseline plan, particularly, a process for identifying population changes around a pipeline segment;

(7) an explanation of methods selected to assess the integrity of line pipe;

(8) a process for review of integrity assessment results and data analysis by a person qualified to evaluate the results and data;

(9) the process and risk factors for determining the baseline assessment interval;

(10) results of the baseline integrity assessment;

(11) the process used for continual evaluation, and risk factors used for determining the frequency of evaluation;

(12) process for integrating and analyzing information about the integrity of a pipeline, information and data used for the information analysis;

(13) results of the information analyses and periodic evaluations;

(14) the process and risk factors for establishing continual re-assessment intervals;

(15) justification to support any variance from the required re-assessment intervals;

(16) integrity assessment results and anomalies found, process for evaluating and repairing anomalies, criteria for repair actions and actions taken to evaluate and repair the anomalies;

(17) other remedial actions planned or taken;

(18) schedule for reviewing and analyzing integrity assessment results;

(19) schedule for evaluation and repair of anomalies, justification to support deviation from required repair times;

(20) risk analysis used to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;

(21) criteria for determining EFRD installation;

(22) criteria for evaluating and modifying leak detection capability;

(23) methods used to measure the program's effectiveness.

Issued in Washington DC on November 14, 2000.

Kelley S. Coyner,
Administrator.

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BILLING CODE 4910-60-P

EXHIBIT BMC-54

distribution. Please contact the Federal Aviation Administration at (907) 271-5438 for a copy.

SUPPLEMENTARY INFORMATION: The Sitka Rocky Gutierrez Airport Master Plan outlined development goals and projects that are anticipated to be necessary over the next 20 or more years at the Airport. This Final EIS discusses the proposed improvements recommended at the Airport over the next five years, which have the potential to result in significant adverse environmental impacts. The FAA and the State of Alaska Department of Transportation and Public Facilities (DOT & PF) propose the following projects recommended over the next five years at the Airport to meet the identified needs. The major actions assessed in this Final EIS include:

- Improvements to the Runway Safety Area.
- Extension of the Parallel Taxiway.
- Relocation of the Airport Seaplane Pullout.
- Installation of an Approach Lighting System.
- Repairs and Improvements to the Airport Seawall.
- Acquisition of Sufficient Property Rights to Lands Needed for Existing and Future Aviation and Airport Uses.

The proposed Airport improvements would be completed during the 2010-2015 time period and, depending on the alternatives implemented, may result in temporary or long-term impacts to the coastal resources, marine environment and wildlife (including species protected under the Endangered Species Act), water quality, wetlands, historical, architectural, archaeological, and cultural resources, terrestrial wildlife and vegetation, and subsistence.

Section 810 of the Alaska National Lands Conservation Act (ANILCA) requires an evaluation on the effects of alternatives presented in this Final EIS on subsistence activities occurring on public lands in the planning area. The evaluation in the Final EIS indicates that none of the alternatives significantly restrict subsistence activities.

If the transfer of title option is selected for the acquisition of property rights, the lands would change from Federal to State ownership. This would result in the loss of Federal subsistence regulations applying on those lands and the irreversible loss of opportunities for a subsistence priority for rural residents from loss of Federal public lands. A long-term lease or easement would preserve opportunities for a subsistence priority for rural residents by retaining Federal ownership of public lands.

The FAA conducted a public hearing on the Draft EIS October 2, 2008 and

received comments on the Draft EIS through October 14, 2008. The FAA has reviewed and responded to the comments received during the Draft EIS comment period and made revisions to the EIS as appropriate.

FOR FURTHER INFORMATION CONTACT: Patricia Sullivan, Environmental Specialist, Federal Aviation Administration, Alaskan Region, Airports Division, 222 W. 7th Avenue #14, Anchorage, AK 99513-7504. Ms. Sullivan may be contacted during business hours at (907) 271-5454 (phone) and (907) 271-2851 (facsimile).

Issued in Anchorage, Alaska on May 14, 2009.

Byron K. Huffman,

Manager, Airports Division, Alaskan Region.

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BILLING CODE 4910-13-M

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA-2009-0148]

Pipeline Safety: Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing an advisory bulletin to owners and operators of natural gas pipeline and hazardous liquid pipeline systems. This bulletin advises pipeline system owners and operators of the potential for high grade line pipe installed on projects to exhibit inconsistent chemical and mechanical properties. Yield strength and tensile strength properties that do not meet the line pipe specification minimums have been reported. This advisory bulletin pertains to microalloyed high strength line pipe grades, generally Grade X-70 and above. PHMSA recently reviewed metallurgical testing results from several recent projects indicating pipe joints produced from plate or coil from the same heat may exhibit variable chemical and mechanical properties by as much as 15% lower than the strength values specified by the pipe manufacturer.

FOR FURTHER INFORMATION CONTACT: Alan Mayberry by phone at (202) 366-5124 or by e-mail at alan.mayberry@dot.gov.

SUPPLEMENTARY INFORMATION:

I. Background

The Federal pipeline safety regulations in 49 CFR Parts 192 and 195 require operators of natural gas transmission, distribution pipeline systems, and hazardous liquids pipeline systems to use pipe manufactured by a listed specification in the design of pipelines in accordance with §§ 192.7, 192.55(a), 192.105, and §§ 195.3, 195.106, and 195.112.

During pipeline construction in the late-fall of 2008, several recently installed natural gas transmission pipeline systems experienced field hydrostatic test failures or excessively expanded pipe joints of large diameter, microalloyed high grade line pipe. Metallurgical, mechanical and chemical composition tests of the line pipe in these cases have shown pipe to have yield strengths, tensile strengths and/or chemical compositions that did not meet the requirements of the American Petroleum Institute, Specification for Line Pipe—5L, (API 5L), 43rd edition for the specified pipe grade. API 5L, product specification level (PSL 2), specifies material requirements in Section 6 and inspection and testing standards in Section 9. Even though the pipe supplier provided the pipeline owner or operator with documentation that the pipe that was delivered to the owner met these minimum standards, substandard pipe properties were found in some pipe joints. Specifically, PHMSA was made aware that some of the line pipe that was installed in these projects had yield strengths that were up to 15% below the listed API 5L specification requirements for the specific pipe grade.

Pipeline owners and operators should closely review the manufacturing procedure specifications for the production and rolling of the steel plate or coil that is to be used in the production of new microalloyed high strength line pipe to ensure that pipe steel was properly rolled into steel plate or coil prior to the pipe mill rolling process. Pipeline owners and operators should request detailed manufacturing procedure specifications (MPS) from the pipe manufacturer as a basis for ensuring critical steel processing parameters such as the detailed rolling schedule, including, but not limited to rolling temperature, heating temperature and temperature uniformity, are controlled throughout the steel rolling process.

Mechanical property and chemical composition tests should be conducted throughout the steel making, steel rolling and pipe manufacturing process to ensure uniformity of chemical and

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

[AC 187-1C]

Schedule of Charges Outside the United States

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of availability.

SUMMARY: The Federal Aviation Administration (FAA) is announcing the availability of Advisory Circular (AC) 187-1C which transmits an updated schedule of charges for services of FAA Flight Standards Aviation Safety Inspectors outside the United States. The advisory circular has been updated in accordance with the procedures listed in 14 CFR Part 187, Appendix A.

DATES: This AC is effective on June 1, 2009.

ADDRESSES: *How to obtain copies:* A copy of this publication may be downloaded from: [http://rgl.faa.gov/Regulatory_and_Guidance_Library/rgAdvisoryCircular.nsf/0/b38e4a75d8e55cae862575b6004e937a/\\$FILE/AC%20187-1C.pdf](http://rgl.faa.gov/Regulatory_and_Guidance_Library/rgAdvisoryCircular.nsf/0/b38e4a75d8e55cae862575b6004e937a/$FILE/AC%20187-1C.pdf).

FOR FURTHER INFORMATION CONTACT: Dr. Geoff McIntyre, Flight Standards Service, AFS-51, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591, telephone (202) 385-8139.

Issued in Washington, DC, on May 14, 2009.

John W. McGraw,
Deputy Director, Flight Standards Service.
[FR Doc. E9-11926 Filed 5-20-09; 8:45 am]

BILLING CODE 4910-13-P

DEPARTMENT OF VETERANS AFFAIRS

Advisory Committee on Structural Safety of Department of Veterans Affairs Facilities; Notice of Meeting

The Department of Veterans Affairs (VA) gives notice under Public Law 92-463 (Federal Advisory Committee Act) that a meeting of the Advisory Committee on Structural Safety of Department of Veterans Affairs Facilities will be held on June 18-19, 2009, in Room 442, Export Import Bank, 811 Vermont Avenue, NW., Washington, DC. The June 18 session will be from 9 a.m. until 5 p.m., and the June 19 session will be from 8:30 a.m. until 12:30 p.m. The meeting is open to the public.

The purpose of the Committee is to advise the Secretary of Veterans Affairs

mechanical properties of the pipe prior to being shipped from the steel and pipe rolling mills. Low yield and tensile strength test results are defined as any test results below the minimum specified yield strength ordered, and tensile strengths below those specified for the specified grade. An example of pipe standard and grades includes API 5L, PSL 2, X70 and X80; where X-70 corresponds to steel achieving a specified minimum yield strength of 70,000 psi; and so on.

II. Advisory Bulletin ADB-09-01

To: Owners and Operators of Hazardous Liquid and Natural Gas Pipeline Systems.

Subject: Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe.

Advisory: The Federal pipeline safety regulations in 49 CFR Parts 192 and 195 require operators of natural gas transmission, gas distribution, and hazardous liquids pipeline systems to use pipe manufactured by a listed specification in the design of pipelines in accordance with §§ 192.7, 192.55 (a), 192.105, and §§ 195.3, 195.106, and 195.112.

PHMSA has identified an integrity issue with respect to microalloyed high grade line pipe. Tests that have been conducted on line pipe that has been installed in pipeline systems have shown that some of the pipe material has yield strengths, tensile strengths, and/or chemical compositions that do not meet the requirements of the American Petroleum Institute, Specification for Line Pipe—5L, (API 5L), for PSL 2 and the specified pipe grade. Pipe joints produced from plate or coil from the same heat may exhibit variable chemical and mechanical properties. Yield strengths below the minimum specified yield strength have been reported and yield strengths up to 15% lower than the strength values on the pipe manufacturer produced mill test report have also been reported. In some cases, the affected pipe may successfully pass strength testing methods contained in current specifications but may lead to a future pipeline integrity issue. The presence of low yield strength line pipe installed in a pipeline system may result in increased susceptibility to excessive pipe expansion or rupture during the pre in-service field hydrostatic strength test.

PHMSA wants to ensure that owners and operators of recently constructed pipeline systems are aware of the need to investigate whether their pipelines contain joints of pipe that do not meet

minimum specification requirements. Pipeline owners and operators should review all MPS mill test reports and other appropriate documentation with their pipe suppliers to determine if all specification requirements have been met. Pipeline owners and operators should be aware that small deviations in steel rolling schedule parameters can have a pronounced effect on final mechanical properties. The MPS should provide adequate information concerning process details and inspection methods to ensure that the materials are uniform and will meet all specification requirements.

PHMSA advises pipeline owners and operators of in service pipelines to review their pipe specifications, pipe steel making and rolling MPS, pipe mill test reports, deformation tool results and all hydrostatic test failure results for both mill and in place hydrostatic tests to ensure that inconsistent mechanical and chemical properties are not inherent in microalloyed line pipe grades on all API 5L—PSL 2, X70 and X80 line pipe installed during recent construction projects.

Pipeline owners and operators should conduct technical document reviews on all high strength microalloyed line pipe installed during this period, review hydrostatic test failures that occurred on pipelines installed during this period and consider using methods to detect pipe expansion such as running deformation tools that detect expanded pipe in these systems if they have any knowledge, findings or pipe history that lead them to believe their newly constructed high grade line pipe systems contain line pipe joints that do not meet specification requirements. Should a pipeline owner or operator have knowledge of other high grade pipe vintages supplied at early dates that are in their operating systems that may have this problem, they should consider conducting reviews as described above with these operating pipelines to ensure that operating pressures and anomaly repair procedures are not being conducted outside of their 49 CFR Parts 192 and 195 Code parameters.

Authority: 49 U.S.C. chapter 601 and 49 CFR 1.53.

Issued in Washington, DC, on May 14, 2009.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.
[FR Doc. E9-11815 Filed 5-20-09; 8:45 am]

BILLING CODE 4910-60-P

EXHIBIT BMC-55

business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of NYSE Arca. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File No. SR-NYSEArca-2010-14 and should be submitted on or before April 8, 2010.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority,¹⁹

Florence E. Harmon,

Deputy Secretary.

[FR Doc. 2010-6507 Filed 3-23-10; 8:45 am]

BILLING CODE 8011-01-P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Finance Docket No. 35359]

Pacific Rim Railway Company, Inc.— Acquisition and Operation Exemption—City of Keokuk, IA

Pacific Rim Railway Company, Inc. (PRIM), a noncarrier, has filed a verified notice of exemption under 49 CFR 1150.31 to acquire from the City of Keokuk, IA and to operate approximately 2,894 feet of railroad trackage (.544-mile) consisting of a 2,194 foot-long railroad bridge over the Mississippi River, commonly known as the Keokuk Municipal Bridge, approximately 600 feet of land and track at the approach to the bridge at Hamilton, IL and approximately 100 feet of land and track at the approach to the bridge at Keokuk (collectively, the Bridge). The Bridge connects trackage at Keokuk with trackage at Hamilton.¹

The transaction is expected to be consummated on or shortly after April 7, 2010 (the effective date of the exemption).

PRIM certifies that its projected annual revenues as a result of the transaction do not exceed those that would qualify it as a Class III rail carrier and further certifies that its projected

annual revenue will not exceed \$5 million.

If the verified notice contains false or misleading information, the exemption is void *ab initio*. Petitions to revoke the exemption under 49 U.S.C. 10502(d) may be filed at any time. The filing of a petition to revoke will not automatically stay the effectiveness of the exemption. Petitions for stay must be filed no later than March 31, 2010 (at least 7 days before the exemption becomes effective).

An original and 10 copies of all pleadings, referring to STB Finance Docket No. 35359, must be filed with the Surface Transportation Board, 395 E Street, SW., Washington, DC 20423-0001. In addition, a copy of each pleading must be served on Thomas F. McFarland, 208 South LaSalle Street, Suite 1890, Chicago, IL 60604.

Board decisions and notices are available on our Web site at <http://www.stb.dot.gov>.

Decided: March 18, 2010.

By the Board, Rachel D. Campbell,
Director, Office of Proceedings.

Kulunie L. Cannon,

Clearance Clerk.

[FR Doc. 2010-6414 Filed 3-23-10; 8:45 am]

BILLING CODE 4915-01-P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Research, Engineering And Development Advisory Committee

Pursuant to section 10(A)(2) of the Federal Advisory Committee Act (Pub. L. 92-463; 5 U.S.C. App. 2), notice is hereby given of a meeting of the FAA Research, Engineering and Development (R,E&D) Advisory Committee.

Agency: Federal Aviation Administration.

Action: Notice of Meeting.

Name: Research, Engineering & Development Advisory Committee.

Time and Date: April 21, 2010—9 a.m. to 5 p.m.

Place: Federal Aviation Administration, 800 Independence Avenue, SW—Round Room (10th Floor), Washington, DC 20591.

Purpose: The meeting agenda will include receiving from the Committee guidance for FAA's research and development investments in the areas of air traffic services, airports, aircraft safety, human factors and environment and energy. Attendance is open to the interested public but seating is limited. Persons wishing to attend the meeting or obtain information should contact Gloria Dunderman at (202) 267-8937 or gloria.dunderman@faa.gov. Attendees will have to present picture ID at the security desk and be escorted to the Round Room.

Members of the public may present a written statement to the Committee at any time.

Dated: Issued in Washington, DC on March 17, 2010.

Barry Scott,

*Director, Research & Technology
Development.*

[FR Doc. 2010-6254 Filed 3-23-10; 8:45 am]

BILLING CODE 4910-13-M

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA-2010-0078]

Pipeline Safety: Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe

AGENCY: Pipeline and Hazardous
Materials Safety Administration
(PHMSA); DOT.

ACTION: Notice; issuance of advisory
bulletin.

SUMMARY: PHMSA is issuing an advisory bulletin to notify owners and operators of recently constructed large diameter natural gas pipeline and hazardous liquid pipeline systems of the potential for girth weld failures due to welding quality issues. Misalignment during welding of large diameter line pipe may cause in-service leaks and ruptures at pressures well below 72 percent specified minimum yield strength (SMYS). PHMSA has reviewed several recent projects constructed in 2008 and 2009 with 20-inch or greater diameter, grade X70 and higher line pipe. Metallurgical testing results of failed girth welds in pipe wall thickness transitions have found pipe segments with line pipe weld misalignment, improper bevel and wall thickness transitions, and other improper welding practices that occurred during construction. A number of the failures were located in pipeline segments with concentrated external loading due to support and backfill issues. Owners and operators of recently constructed large diameter pipelines should evaluate these lines for potential girth weld failures due to misalignment and other issues by reviewing construction and operating records and conducting engineering reviews as necessary.

FOR FURTHER INFORMATION CONTACT:
Alan Mayberry by phone at 202-366-
5124 or by e-mail at
alan.mayberry@dot.gov.

SUPPLEMENTARY INFORMATION:

¹⁹ 17 CFR 200.30-3(a)(12).

¹ PRIM states that, because the Bridge is part of a through route for rail transportation, it is a "railroad line" under 49 U.S.C. 10901(a)(4). Rail transportation over the Bridge is currently being performed by Keokuk Junction Railway Company (KJRY), a Class III rail carrier. PRIM does not propose to operate over the Bridge, but acknowledges that, as owner of the Bridge, it would have a residual common carrier obligation to provide rail transportation in the event KJRY ceases to do so. PRIM seeks an exemption for operation on that basis.

I. Background

The Federal pipeline safety regulations in 49 CFR Parts 192 and 195 require operators of natural gas transmission, distribution, and hazardous liquids pipeline systems to construct their pipelines using pipe, fittings, and bends manufactured in accordance with 49 CFR §§ 192.7, 192.53, 192.55, 192.143, 192.144, 192.149, 195.3, 195.101, 195.112, and 195.118 and incorporated standards and listed design specifications. This involves reviewing the manufacturing procedure specification details for weld end conditions for the line pipe, fitting, bend, or other appurtenance from the manufacturer to ensure weld end conditions are acceptable for girth welding.

During the 2008 and 2009 pipeline construction periods, several newly constructed large diameter, 20-inch or greater, high strength (API 5L X70 and X80) natural gas and hazardous liquid pipelines experienced field hydrostatic test failures, in-service leaks, or in-service failures of line pipe girth welds. Post-incident metallurgical and mechanical tests and inspections of the line pipe, fittings, bends, and other appurtenances indicated pipe with weld misalignment, improper bevels of transitions, improper back welds, and improper support of the pipe and appurtenances. In some cases, pipe end conditions did not meet the design and construction requirements of the applicable standards including:

- American Petroleum Institute (API), *Specification for Line Pipe*—5L, (API 5L), 43rd (including Table 8—*Tolerance for Diameter at Pipe Ends* and Table 9—*Tolerances for Wall Thickness*) or 44th editions for the specified pipe grade;
- API 1104, 19th and 20th editions, *Welding of Pipelines and Related Facilities*;
- American Society of Mechanical Engineers (ASME) B31.8, *Gas Transmission and Distribution Piping Systems* or ASME B31.4 *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*; and
- Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) MSS-SP-44-1996 *Steel Pipeline Flanges* and MSS MSS-SP-75-2004 *Specification for High-Test, Wrought, Butt-Welding Fittings*.

Post-incident findings were that in some cases the pipe and induction bend girth weld bevels were not properly transitioned and aligned during welding. In some cases, the girth weld pipe ends did not meet API 5L pipe end diameter and diameter out-of-roundness specifications. Many of the problematic

girth welds did not meet API 1104 misalignment and allowable “high-low” criteria.

Some girth welds that failed in-service had non-destructive testing (NDT) quality control problems. NDT procedures, including radiographic film and radiation source selection, were not properly optimized for weld defect detection and repairs. This was particularly the case where there were large variations in wall thickness at transitions. In some situations, NDT procedures were not completed in accordance with established API 1104 and operator procedures.

Many of the integrity issues with transition girth welds were present on pipelines being constructed in hilly terrain and high stress concentration locations such as at crossings, streams, and sloping hillsides with unstable soils. These girth welds had high stress concentrations in the girth weld transitions due to the combination of large variations in wall thickness and improper internal bevels with inadequate pipe support, poor backfill practices and soil movement due to construction activities.

II. Advisory Bulletin ADB-10-03

To: Owners and Operators of Hazardous Liquid and Natural Gas Pipeline Systems.

Subject: Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe.

Advisory: Owners and operators of recently constructed large diameter pipelines should evaluate these lines for potential girth weld failures due to misalignment and other issues by reviewing construction and operating records and conducting engineering reviews as necessary. The assessments should cover all large diameter, 20-inch or greater, high strength line pipe transitions and cut factory bends or induction bends installed during 2008 and 2009, and should include material specifications, field construction procedures, caliper tool results, deformation tool results, welding procedures including back welding, NDT records, and any failures or leaks during hydrostatic testing or in-service operations to identify systemic problems with pipe girth weld geometry/out-of-roundness, diameter tolerance, and wall thickness variations that may be defective.

The reviews should ensure that pipelines were constructed in compliance with the Federal pipeline safety regulations in 49 CFR Parts 192 and 195. Operators of natural gas transmission, distribution, and

hazardous liquids pipeline systems are required to use pipe and fittings manufactured in accordance with 49 CFR §§ 192.7, 192.53, 192.55, 192.143, 192.144, 192.149, 195.3, 195.101, 195.112, and 195.118 and incorporated standards and listed design specifications.

With respect to the construction process, pipe, fittings, factory bends, and induction bends must be made in accordance with the applicable standards to ensure that weld end dimension tolerances are met for the pipe end diameter and diameter out-of-roundness. API 1104 specifies girth weld misalignment and allowable “high-low” criteria. API 1104—19th edition, § 7.2, *Alignment*, specifies for pipe ends of the same nominal thickness that the offset should not exceed 1/8 inch (3mm) and when there is greater misalignment, it shall be uniformly distributed around the circumference of the pipe, fitting, bend, and other appurtenance. ASME B31.4, Figure 434.8.6(a)-(2), *Acceptable Butt Welded Joint Design for Unequal Wall Thickness* and ASME B31.8, Figure I5, *Acceptable Design for Unequal Wall Thickness*, give guidance for wall thickness variations and weld bevels designs for transitions. API 5L, 43rd edition in Table 8—*Tolerance for Diameter at Pipe Ends* and Table 9—*Tolerances for Wall Thickness*, specifies tolerances for pipe wall thickness and pipe end conditions for diameter and diameter out-of-roundness. MSS-SP-44-1996 specifies weld end tolerances in § 5.3—*Hub Design*, § 5.4—*Welding End*, Figure 1—*Acceptable Designs for Unequal Wall Thickness*, and Figures 2 and 3; and MSS-75-2004 specifies weld end tolerances in § 13.3 and Figures 1, 2, and 3 and Table 3—*Tolerances*.

Pipeline owners and operators should closely review the manufacturing procedure specifications for the production, rolling, and bending of the steel pipe, fittings, bends, and other appurtenances to make sure that pipe end conditions (diameter and out of roundness tolerances) and transition bevels are suitable for girth welding. Pipeline owners and operators should request or specify manufacturing procedure specification details for weld end conditions for the line pipe, fitting, bend, or other appurtenance from the manufacturer to ensure weld end conditions are acceptable for girth welding.

To ensure the integrity of the pipeline, field personnel that weld line pipe, fittings, bends, and other appurtenances must be qualified, follow qualified procedures, and operators must document the work performed. Operators should verify that field

practices are conforming to API 5L, API 1104, ASME B31.4 or ASME B31.8 and operator procedures for weld bevel, pipe alignment, back welding, and transitions. If any bends are cut, the operator must have procedures to ensure that the pipe or bend cut ends are acceptable for welding in accordance with the listed specifications. Procedures, inspection, and documentation must be in place to ensure that when pipe, fittings, bends, and other appurtenances are welded, the field girth welds are made and non-destructively tested in accordance with 49 CFR §§ 192.241, 192.243, 192.245, 195.228, 195.230, and 195.234. NDT procedures including film type and radiation source selection should be optimized for weld defect detection and repairs completed in accordance with established welding procedures. When there is a variation in wall thickness between line pipe and a segmented fitting, bend, or other appurtenance, consideration should be given to the installation of a segment of intermediate wall thickness pipe. Additionally, efforts should be taken to ensure pipe girth weld alignment is optimized by utilizing experienced and trained welders, suitable pipe and detailed procedures.

Each material component of a pipeline such as line pipe, fittings, bends, and other appurtenances must be able to withstand operating pressures and other anticipated external loadings without impairment of its serviceability in accordance with 49 CFR §§ 192.143 and 195.110. In order to ensure pipeline integrity, the operator must take all practicable steps to protect each transmission line from abnormal loads while backfilling and other work continues along the right-of-way and to minimize loads in accordance with 49 CFR §§ 192.317, 192.319, 195.246(a), and 195.252. Operators should give special attention to girth welds with variations in wall thickness when located in pipeline segments where significant pipe support and backfill settlement issues after installation may be present, specifically in hilly terrain and high stress concentration locations such as at crossings, streams, and sloping hill sides with unstable soils.

Even if no girth weld concerns are identified by reviewing construction records, if an operator has any knowledge, findings or operating history that leads it to believe that its newly constructed, high material grade, large diameter, line pipe segments contain these type girth weld transitions, the operator should conduct engineering reviews as described above with those operating pipelines to ensure that

material, engineering design, and field construction procedures were in compliance with 49 CFR Parts 192 and 195. Failure to conduct engineering reviews and to remediate findings may compromise the safe operation of the pipeline.

Authority: 49 U.S.C. chapter 601 and 49 CFR 1.53.

Issued in Washington, DC, on March 18, 2010.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. 2010-6528 Filed 3-23-10; 8:45 am]

BILLING CODE 4910-60-P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

Voluntary Intermodal Sealift Agreement

AGENCY: Maritime Administration, DOT.

ACTION: Notice of Voluntary Intermodal Sealift Agreement (VISA).

SUMMARY: The Maritime Administration (MARAD) announces the extension of the Voluntary Intermodal Sealift Agreement (VISA) until October 1, 2011, pursuant to the Defense Production Act of 1950, as amended. The purpose of the VISA is to make intermodal shipping services/systems, including ships, ships' space, intermodal equipment and related management services, available to the Department of Defense as required to support the emergency deployment and sustainment of U.S. military forces. This is to be accomplished through cooperation among the maritime industry, the Department of Transportation and the Department of Defense.

FOR FURTHER INFORMATION CONTACT: Jerome D. Davis, Director, Office of Sealift Support, Room W25-310, Maritime Administration, 1200 New Jersey Avenue, SE., Washington, DC 20590, (202) 366-2323, Fax (202) 366-5904.

SUPPLEMENTARY INFORMATION: Section 708 of the Defense Production Act of 1950, as amended, (50 U.S.C. App. 2158), as implemented by regulations of the Federal Emergency Management Agency (44 CFR Part 332), "Voluntary agreements for preparedness programs and expansion of production capacity and supply", authorizes the President, upon a finding that conditions exist which may pose a direct threat to the national defense or its preparedness programs, "* * * to consult with representatives of industry, business, financing, agriculture, labor and other interests * * *" in order to provide the

making of such voluntary agreements. It further authorizes the President to delegate that authority to individuals who are appointed by and with the advice and consent of the Senate, upon the condition that such individuals obtain the prior approval of the Attorney General after the Attorney General's consultation with the Federal Trade Commission. Section 501 of Executive Order 12919, as amended, delegated this authority of the President to the Secretary of Transportation (Secretary), among others. By DOT Order 1900.9, the Secretary delegated to the Maritime Administrator the authority under which the VISA is sponsored. Through advance arrangements in joint planning, it is intended that participants in VISA will provide capacity to support a significant portion of surge and sustainment requirements in the deployment of U.S. military forces during war or other national emergency.

The text of the VISA was first published in the **Federal Register** on February 13, 1997, to be effective for a two-year term until February 13, 1999. The VISA document has been extended and subsequently published in the **Federal Register** every two years. The last extension was published on November 7, 2007. The text published herein will now be implemented. Copies will be made available to the public upon request.

Text of the Voluntary Intermodal Sealift Agreement:

Voluntary Intermodal Sealift Agreement (VISA)

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EXHIBIT BMC-56



U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

December 8, 2022

VIA ELECTRONIC MAIL TO: richard_prior@tcenergy.com

Richard Prior
TC Oil Pipeline Operations, Inc.
700 Louisiana Suite 700
Houston, TX 77002

Re: CPF No. 3-2022-074-CAO

Dear Mr. Prior,

Enclosed please find a Corrective Action Order (CAO or Order) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), in the above-referenced case. It requires TC Oil Pipeline Operations, Inc., to take certain corrective actions with respect to a pipeline failure that occurred on December 7, 2022, on the 36-inch Keystone pipeline three miles east of Washington, Kansas.

Service of the CAO by electronic mail is effective upon the date of transmission and acknowledgment of receipt as provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Sincerely,

ALAN KRAMER
MAYBERRY

Digitally signed by ALAN
KRAMER MAYBERRY
Date: 2022.12.08
18:22:43 -05'00'

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure: CAO

cc: Mr. Gregory Ochs, Director, Central Region, Office of Pipeline Safety, PHMSA

CONFIRMATION OF RECEIPT REQUESTED

**U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590**

In the Matter of)
)
TC Oil Pipeline Operations, Inc.,) **CPF No. 3-2022-074-CAO**
)
Respondent.)
)
)
)
)

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order (CAO or Order) is being issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), under the authority of 49 U.S.C. § 60112, to require TC Oil Pipeline Operations, Inc. (TC Oil or Respondent), to take necessary corrective actions to protect the public, property, and the environment from potential hazards associated with the December 7, 2022, crude oil pipeline failure that occurred on the 36-inch Keystone pipeline, approximately three miles east of Washington, Kansas (Failure).

The Keystone Pipeline is a 2,687-mile hazardous liquid pipeline system between Hardisty, Alberta, Canada, and Patoka, Illinois, and Port Arthur, Texas.¹ The 36-inch diameter Cushing Extension was Phase 2 of the Keystone pipeline. Construction was completed in 2011 for the Cushing Extension. The Cushing Extension begins in Steele City, Nebraska and goes to Cushing, Oklahoma, and is approximately 288 miles long. The MOP of the pipeline is 1,440 psig, and it operates under Special Permit PHMSA-2006-26617.

At approximately 09:01 PM CST a leak detection alarm (volume imbalance) was received. An Emergency-Line Trip alarm was received 6-minutes later. The pipeline was subsequently shut down and isolation valves were commanded closed at 09:08 PM CST. The location of the Failure is Cushing Extension, MP 14. The affected segment of the pipeline spans from Steele City pump station (MP 0.0) to Hope pump station (MP 95.7, approximately). Upon receiving the leak alarms, TC Oil personnel were dispatched and identified a crude oil odor north of U.S. Highway 36. The failure location was subsequently confirmed to be approximately two miles north of the highway crossing. Crude Oil from the pipeline has impacted Mill Creek, at approximate coordinates of 39-degrees, 50-minutes, 33-seconds, and -96-degrees, 59-minutes, 44-seconds.

¹ See Overview, TC ENERGY, <https://www.tcenergy.com/operations/oil-and-liquids/keystone-pipeline-system/> (last accessed Dec. 8, 2022)

TC Oil was in the process of running an in-line inspection (ILI) tool. The ILI tool is currently downstream of the failure location. Respondent had bypassed the Hope, Kansas, pump station, the next station downstream, in preparation for the tool to pass when the failure occurred.

Pursuant to 49 U.S.C. § 60117, PHMSA has initiated an investigation of the Failure. The preliminary findings of the Agency's ongoing investigation are as follows:

Preliminary Findings

- On December 7, 2022, at approximately 09:01 PM CST a leak detection alarm (volume imbalance) was received. An Emergency-Line Trip alarm was received 6-minutes later.
- The pipeline was shut down and isolation valves were commanded closed at 09:08 PM CST.
- Upon receiving notification of the Failure, TC Oil personnel were dispatched and identified a crude oil odor north of U.S. Highway 36. The Failure location was subsequently confirmed approximately two miles north of the highway crossing.
- The location of the Failure is Cushing Extension, MP 14. The affected segment of the pipeline spans from Steele City pump station (MP 0.0) to Hope pump station (MP 95.7, approximately).
- The pipeline is a 36-inch diameter, 0.465-inch wall thickness, Grade X-70, and manufactured by Evraz. The MOP is 1,440 psig.
- The 36-inch diameter Cushing Extension was Phase 2 of the Keystone pipeline. Construction was completed in 2011 for the Cushing Extension. The Cushing Extension begins in Steele City, Nebraska and goes to Cushing, Oklahoma, and is approximately 288 miles long.
- Crude Oil from the pipeline has impacted Mill Creek crossing, at approximate coordinates of 39-degrees, 50-minutes, 33-seconds, and -96-degrees, 59-minutes, 44-seconds.
- Keystone pipeline traverses several High Consequence Areas and navigable rivers. The Keystone pipeline Cushing Extension traverses could affect HCA areas
- TC Oil was in the process of running an ILI tool. The ILI tool is currently downstream of the failure location. TC Oil had bypassed the Hope, Kansas, pump station, the next station downstream, in preparation for the tool to pass when the failure occurred.
- The initial estimated spill volume is approximately 14,000 barrels of crude oil.\
- On May 7, 2011, a reportable accident occurred on pump station piping on the Keystone crude oil pipeline at the Ludden Pump Station. On May 29, 2011, a second reportable

failure incident occurred on piping at the Severance Pump Station. On June 3, 2011, PHMSA issued a Corrective Action Order requiring Respondent to take corrective actions (CPF No. 3-2011-5006H). On June 13, 2011, Respondent submitted a response to this CAO requesting a hearing. Following informal discussions between Respondent and PHMSA, based on the most up-to-date information, PHMSA agreed to make minor changes and clarifications to the original CAO in an Amended CAO issued June 28, 2011. The Order was closed on January 13, 2015, after TC Oil had completed all the required corrective actions.

- On April 2, 2016, a reportable accident due to a leak in a cracked tie-in weld occurred on the Keystone pipeline on the 48.1-mile segment between Freeman (Pump Station 23) and Hartington (Pump Station 24). On April 9, 2016, PHMSA issued a Corrective Action Order requiring Respondent to take corrective actions (CPF No. 3-2016-5002H). The Order was closed on March 30, 2017, after TC Oil had completed all the required corrective actions.
- PHMSA issued a Corrective Action Order (CPF No. 3-2017-5008H) to TC Oil on November 28, 2017, due to a fracture that initiated at an area of previous mechanical damage. This Order was closed on January 29, 2019, after Respondent completed all the required corrective actions.
- On October 30, 2019, a reportable accident occurred on the 41.9-mile Keystone pipeline segment that runs between the Edinburg Pump Station and the Niagara Pump Station, near Niagara, North Dakota. On November 5, 2019, PHMSA issued a Corrective Action Order requiring Respondent to take corrective action (CPF No. 3-2019-5023H). The Order was closed on February 3, 2022, after TC Oil had completed all the required corrective actions.
- On October 14, 2022, PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (CPF No. 3-2022-025-NOPV) following a special inspection of TC Oil's Lucas delivery facility in Beaumont, Texas, following a crude oil spill that occurred there on May 7, 2020. The proceeding remains open at this time.
- The investigation is on-going, and information could change. This order may be amended based on further findings during the investigation.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of title 49, United States Code, authorizes PHMSA to determine that a pipeline facility is or would be hazardous to life, property, or the environment and if there is a likelihood of serious harm, to expeditiously order the operator of the facility to take necessary corrective action, including suspended or restricted use of the facility, physical inspection, testing, repair, replacement, or other appropriate action. An order issued expeditiously must provide an opportunity for a hearing as soon as practicable after the order is issued.

In deciding whether to issue an order, PHMSA must consider the following, if relevant: (1) the characteristics of the pipe and other equipment used in the pipeline facility, including the age, manufacture, physical properties, and method of manufacturing, constructing, or assembling the equipment; (2) the nature of the material the pipeline facility transports, the corrosive and deteriorative qualities of the material, the sequence in which the material is transported, and the pressure required for transporting the material; (3) the aspects of the area in which the pipeline facility is located, including climatic and geologic conditions and soil characteristics; (4) the proximity of the area in which the hazardous liquid pipeline facility is located to environmentally sensitive areas; (5) the population density and population and growth patterns of the area in which the pipeline facility is located; (6) any recommendation of the National Transportation Safety Board made under another law; and (7) any other factors PHMSA may consider as appropriate.

After evaluating the foregoing preliminary findings of fact, and having considered the characteristics of the pipeline, including the prior failures of the pipeline; the hazardous nature of the material (crude oil) transported; the uncertainty as to the root cause(s) of the Failure; the existing and potential additional impacts to property, the environment, and wildlife; and the possibility that the same condition(s) that may have caused the failure remain present in the pipeline and could lead to additional failures; I find that continued operation of the *Affected Segment*, as defined below, without corrective measures is or would be hazardous to life, property, or the environment, and that failure to issue this Order expeditiously would result in the likelihood of serious harm.

Accordingly, this Order mandating immediate corrective action is issued expeditiously without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, PHMSA, OPS Central Region. If a hearing is requested, it will be held in accordance with 49 C.F.R. § 190.211.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. Respondent will be notified of any additional measures required and, if appropriate, PHMSA will consider amending this Order. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions

Definitions:

Affected Segment – The “*Affected Segment*” means approximately 96 miles of TC Oil’s Keystone pipeline that contains the 36-inch diameter pipe from Steele City pump station (MP 0.0) to Hope pump station (MP 95.7, approximately). The *Affected Segment* traverses the following counties: Jefferson County NE, Washington County KS, Clay County KS, and Dickinson County KS.

Director – The "*Director*" means the Director, PHMSA, OPS Central Region.

Pursuant to 49 U.S.C. 60112, I hereby order TC Oil to take the following corrective actions:

1. ***Shutdown of the Affected Segment.*** The *Affected Segment* must remain shut-in and may not be operated until authorized to be restarted by the Director in accordance with the terms of this Order.
2. ***Operating Pressure Restriction.*** TC Oil must reduce and maintain a twenty percent (20%) pressure reduction in the actual operating pressure along the entire length of the *Affected Segment* such that upon restart the operating pressure along the *Affected Pipeline* will not exceed eighty percent (80%) of the actual operating pressure in effect at the failure location, immediately prior to the failure on December 7, 2022.
 - a. This pressure restriction is to remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director.
 - b. Within 15 days of receipt of the CAO, TC Oil must provide the Director the actual operating pressures of each pump station on the *Affected Segment* at the time of failure and the reduced pressure restriction set-points at these same locations.
 - c. This pressure restriction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly.
 - d. When determining the pressure restriction set-points, TC Oil must take into account any in-line inspection (ILI) features or anomalies present in the *Affected Segment* to provide for continued safe operation while further corrective actions are completed.
 - e. TC Oil must review the pressure restriction monthly by analyzing the operating pressure data, taking into account any ILI features or anomalies present in the *Affected Segment*. TC Oil must immediately reduce the operating pressure further to maintain the safe operations of the *Affected Segment*, if warranted by the monthly review. Further, TC Oil must submit the results of the monthly review to the Director including, at a minimum, the current discharge set-points (including any additional pressure reductions), and any pressure exceedance at discharge set-points. Submittals may be made quarterly, in accordance with Item 15 below.
3. ***Review of Prior In-line Inspection (ILI) Results.***
 - a. Within 30 days of receipt of the CAO, TC Oil must conduct a review of any previous ILI results of the *Affected Segment*. In its review, TC Oil must re-evaluate all ILI results from the past 10 calendar years, including a review of the ILI vendors' raw data and analysis. TC Oil must determine whether any features were present in the failed pipe joints from the December 7, 2022, failure. Also, TC Oil must determine if any features with similar characteristics are present elsewhere on the *Affected Segment*. TC Oil must submit documentation of this ILI review to the Director within 45 days of receipt of the CAO, as follows:
 - i. List all ILI tool runs, tool types, and the calendar years of the tool runs.

- ii. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features present in the failed joint and other pipe removed.
 - iii. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features with similar characteristics present elsewhere on the *Affected Segment*.
 - iv. Explain the process used to review the ILI results and the results of the reevaluation.
4. ***Mechanical and Metallurgical Testing.*** Within 45 days of receipt of the CAO, TC Oil must complete mechanical and metallurgical testing and failure analysis of the failed pipe, including an analysis of soil samples and any foreign materials. Mechanical and metallurgical testing must be conducted by an independent third-party acceptable to the Director, and must document the decision-making process and all factors contributing to the failure. TC Oil must complete the testing and analysis as follows:
- a. Document the chain-of-custody when handling and transporting the failed pipe section and other evidence from the failure site.
 - b. Within 10 days of receipt of the CAO, develop and submit the testing protocol and the proposed testing laboratory to the Director for prior approval.
 - c. Prior to beginning the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow for an OPS representative to witness the testing.
 - d. Ensure the testing laboratory distributes all reports whether draft or final in their entirety to the Director at the same time they are made available to TC Oil.
5. ***Root Cause Failure Analysis.*** Within 90 days following receipt of the CAO, complete a root cause failure analysis (RCFA) and submit a final report of this RCFA to the Director. The RCFA must be supplemented or facilitated by an independent third-party acceptable to the Director and must document the decision-making process and all factors contributing to the failure. The final report must include findings and any lessons learned and whether the findings and lessons learned are applicable to other locations within TC Oil's pipeline system.
6. ***Remedial Work Plan (RWP).***
- a. Within 90 days following receipt of the CAO, TC Oil must submit a remedial work plan (RWP) to the Director for approval.
 - b. The Director may approve the RWP incrementally without approving the entire RWP.
 - c. Once approved by the Director, the RWP will be incorporated by reference into this Order.
 - d. The RWP must specify the tests, inspections, assessments, evaluations, and remedial measures TC Oil will use to verify the integrity of the *Affected Segment*. It must address all known or suspected factors and causes of the December 7, 2022, failure. TC Oil must consider the risks and consequences of another failure to develop a prioritized schedule for RWP-related work along the *Affected*

Segment.

- e. The RWP must include a procedure or process to:
- i. Identify pipe in the *Affected Segment* with characteristics similar to the contributing factors identified for the December 7, 2022, failure, including the age and manufacture of the entire length of the *Affected Segment*.
 - ii. Gather all data necessary to review the failure history (in service and pressure test failures) of the *Affected Segment* and to prepare a written report containing all the available information such as the locations, dates, and causes of leaks and failures.
 - iii. Integrate the results of the metallurgical testing, root cause failure analysis, and other corrective actions required by this Order with all relevant pre-existing operational and assessment data for the *Affected Segment*. Pre-existing operational data includes, but is not limited to, design, construction, operations, maintenance, testing, repairs, prior metallurgical analyses, and any third-party consultation information. Pre-existing assessment data includes, but is not limited to, ILI tool runs, hydrostatic pressure testing, direct assessments, close interval surveys, and DCVG/ACVG surveys.
 - iv. Determine if conditions similar to those contributing to the failure on December 7, 2022, are likely to exist elsewhere on the *Affected Segment*.
 - v. Conduct additional field tests, inspections, assessments, and evaluations to determine whether, and to what extent, the conditions associated with the failure on December 7, 2022, and other failures from the failure history (see (e)(ii) above) or any other integrity threats are present elsewhere on the *Affected Segment*. At a minimum, this process must consider all failure causes and specify the use of one or more of the following:
 - 1) ILI tools that are technically appropriate for assessing the pipeline system based on the cause of failure on December 7, 2022, and that can reliably detect and identify anomalies,
 - 2) Hydrostatic pressure testing,
 - 3) Close-interval surveys,
 - 4) Cathodic protection surveys, to include interference surveys in coordination with other utilities (e.g., underground utilities, overhead power lines, etc.) in the area,
 - 5) Coating surveys,
 - 6) Stress corrosion cracking surveys,
 - 7) Selective seam corrosion surveys; and
 - 8) Other tests, inspections, assessments, and evaluations appropriate for the failure causes.

Note: TC Oil may use the results of previous tests, inspections, assessments, and evaluations if approved by the Director, provided the results of the tests, inspections, assessments, and evaluations are analyzed with regard to the factors known or suspected to have caused the December 7, 2022, failure.

- vi. Describe the inspection and repair criteria TC Oil will use to prioritize, excavate, evaluate, and repair anomalies, imperfections, and other identified integrity threats. Include a description of how any defects will be graded and a schedule for repairs or replacement.
 - vii. Based on the known history and condition of the *Affected Segment*, describe the methods TC Oil will use to repair, replace, or take other corrective measures to remediate the conditions associated with the pipeline failure on December 7, 2022, and to address other known integrity threats along the *Affected Segment*. The repair, replacement, or other corrective measures must meet the criteria specified in (e)(vi) above.
 - viii. Implement continuing long-term periodic testing and integrity verification measures to ensure the ongoing safe operation of the *Affected Segment* considering the results of the analyses, inspections, evaluations, and corrective measures undertaken pursuant to the Order.
- f. Include a proposed schedule for completion of the RWP.
- g. TC Oil must revise the RWP as necessary to incorporate new information obtained during the failure investigation and remedial activities, to incorporate the results of actions undertaken pursuant to this Order, and to incorporate modifications required by the Director.
- i. Submit any plan revisions to the Director for prior approval.
 - ii. The Director may approve plan revisions incrementally.
 - iii. All revisions to the RWP after it has been approved and incorporated by reference into this Order will be fully described and documented in the *CAO Documentation Report*.
- h. Implement the RWP as it is approved by the Director, including any revisions to the plan.
7. ***CAO Documentation Report (CDR)***. TC Oil must create and revise, as necessary, a CAO Documentation Report (CDR). When TC Oil has concluded all the items in this Order it will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by SNG with regards to this Order prior to approving the closure of this Order. The intent is for the CDR to summarize all activities and documentation associated with this Order in one document.
- a. The Director may approve the CDR incrementally without approving the entire CDR.
 - b. Once approved by the Director, the CDR will be incorporated by reference into this Order.
 - c. The CDR must include, but is not necessarily limited to, the following:
 - i. Table of Contents;
 - ii. Summary of the pipeline failure of December 7, 2022, and the response activities;
 - iii. Summary of pipe data, material properties, and all prior assessments of the *Affected Pipeline*;

- iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by the Order;
 - v. Summary of the mechanical and metallurgical testing as required by the Order;
 - vi. Summary of the RCFA with all root causes as required by the Order;
 - vii. Documentation of all actions taken by TC Oil to implement the RWP, the results of those actions, and the inspection and repair criteria used;
 - viii. Documentation of any revisions to the RWP including those necessary to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities;
 - ix. Lessons learned while completing this Order;
 - x. A path forward describing specific actions TC Oil will take on its entire pipeline system as a result of the lessons learned from work on this Order; and
 - xi. Appendices (if required).
8. ***Restart Plan.*** Prior to resuming operation of the *Affected Segment*, develop and submit a written *Restart Plan* to the Director for prior approval.
- a. The Director may approve the *Restart Plan* incrementally without approving the entire plan, but the *Affected Segment* cannot resume operation until the *Restart Plan* is approved in its entirety.
 - b. Once approved by the Director, the *Restart Plan* will be incorporated by reference into this Order.
 - c. The *Restart Plan* must provide for adequate patrolling of the *Affected Segment* during the restart process and must include incremental pressure increases during start up, with each increment to be held for at least 2 hours.
 - d. The *Restart Plan* must include sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes.
 - e. The *Restart Plan* must specify a daylight restart and include advance communications with local emergency response officials and adjacent landowners.
 - f. The *Restart Plan* must provide for a review of the *Affected Segment* for conditions similar to those of the failure including a review of construction, operating and maintenance (O&M) and integrity management records such as ILI results, hydrostatic tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion, cathodic protection, excavations and pipe replacements. TC Oil must address any findings that require remedial measures to be implemented prior to restart.
 - g. The *Restart Plan* must also include documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into TC Oil's O&M procedures manual.

9. ***Return to Service.*** After the Director approves the *Restart Plan*, TC Oil may resume operation of the *Affected Segment* according to the terms of the *Restart Plan*, but the operating pressure must not exceed the limit in accordance with Item 2 above.

Other Requirements:

10. ***Approvals.*** With respect to each submission under this Order that requires the approval of the Director, the Director may: (a) approve, in whole or part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent shall proceed to take all action required by the submission as approved or modified by the Director. If the Director disapproves all or any portion of the submission, Respondent must correct all deficiencies within the time specified by the Director and resubmit it for approval.
11. ***Extensions of Time.*** The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.
12. ***Reporting.*** Submit quarterly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first quarterly report is due on March 8, 2023. The Director may change the interval for the submission of these reports.
13. ***Documentation of the Costs.*** It is requested that Respondent maintain documentation of the costs associated with implementation of this CAO. Include in each monthly report submitted, the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

In your correspondence on this matter, please refer to “CPF No. 3-2022-074-CAO” and for each document you submit, please provide a copy in electronic format whenever possible. The actions required by this Order are in addition to and do not waive any requirements that apply to Respondent’s pipeline system under 49 C.F.R. Parts 190 through 199, under any other order

issued to Respondent under authority of 49 U.S.C. Chapter 601, or under any other provision of federal or state law.

Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

The terms and conditions of this Order are effective upon service in accordance with 49 C.F.R. § 190.5.

ALAN KRAMER
MAYBERRY

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KRAMER MAYBERRY
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December 8, 2022

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Date Issued

EXHIBIT BMC-57

Enbridge Inc. Natural Gas Pipeline Rupture

Hillsboro, Kentucky

May 4, 2020

1. Factual Information

1.1 Accident Summary



Figure 1. Ruptured pipeline. (Source: BGC Engineering USA, Inc.)

On May 4, 2020, about 4:36 p.m. local time, a 30-inch diameter interstate natural gas transmission pipeline owned and operated by Enbridge Inc. (Enbridge) ruptured about 3 miles east-northeast of Hillsboro, Kentucky, resulting in a fire.¹ (See figure 1.) The rupture occurred on Line 10 at a hillside location that was previously identified by Enbridge for geotechnical monitoring because of an active landslide.²

Line 10 was the northernmost of three parallel pipelines—Lines 10, 15 and 25—along the same right-of-way. At the time of the rupture, Line 10's operating pressure was about 674 pounds per square inch, gauge.³ The rupture occurred at a girth weld at an elevation of about 923

¹ (a) For more detailed information about this investigation, see the [public docket](#) and search for number PLD20LR001. Use the [CAROL Query](#) to search safety recommendations and investigations. (b) All times in this report are local time unless otherwise noted.

² The rupture occurred on a Texas Eastern Transmission, Limited Partnership, pipeline. Texas Eastern Transmission is an indirect, 100-percent-owned subsidiary of Enbridge Inc.

³ The maximum allowable operating pressure of the pipeline was 936 pounds per square inch, gauge.

feet.⁴ There were no fatalities or injuries, and Enbridge estimated the cost of property damage and emergency response at \$11.7 million.

1.2 Integrity Management

In the years before the rupture, several indications were available to Enbridge that Line 10 was exposed to external loads (loads transmitted to a pipeline from an external source):

- Results of an April 17, 2018, in-line inspection (ILI) indicated pipeline movement of about 4.2 feet.⁵
- On October 9, 2018, Enbridge identified the rupture location as a potential geohazard.
- On April 16, 2019, an aerial patrol observed erosion on the right-of-way near the rupture location.
- Results of a June 7, 2019, ILI indicated pipeline movement of about 5.2 feet.
- A July 8, 2019, ground inspection identified scarps.⁶

In 2019 and 2020, Enbridge evaluated Line 10 for geohazard threats. After a site assessment in October 2019 and analysis comparing the strain exerted on the pipeline (tensile strain demand) to the strain capacity of the pipeline (tensile strain capacity), Enbridge determined that urgent action was not required but recommended monitoring and mitigation of the identified threats.⁷

In February 2020, Enbridge held a multidisciplinary review meeting to determine the monitoring and mitigation plan for this location. Based on estimated tensile strain demand and other geotechnical considerations, Enbridge planned to install strain gauges and improve drainage. According to Enbridge, they also planned to complete

⁴ A *girth weld* is used to join two pipes along their circumference. The girth weld that ruptured had been hydrostatically tested before the pipeline's initial service in 1952 and retested in 1986; a hydrostatic test involves filling the pipeline with water at a predetermined pressure to test the pipeline's integrity.

⁵ *In-line inspection* is an internal pipeline inspection technique that uses magnetic flux leakage, ultrasound, eddy current or other sensing technology to locate and characterize indications of defects, such as metal loss or deformation in the pipeline.

⁶ A *scarp* is a steep surface of exposed material produced by differential, or non-uniform, ground surface movement.

⁷ (a) The *tensile strain demand* is the amount of strain that is being exerted on the system or material, whereas the *tensile strain capacity* is the amount of strain that the system or material can withstand; strain can be expressed as a ratio or percentage. (b) Enbridge estimated a tensile strain demand of 0.6 percent by adding the maximum bending strain at a girth weld to the estimated axial strain. (c) The tensile strain capacity analysis assumed a flaw 2 inches in length and 0.0394 inches in depth. (d) After applying a safety factor, Enbridge determined that the tensile strain capacity threshold was 1 percent for the girth welds.

additional monitoring, mitigation and stress relief in summer 2020. The rupture occurred before the monitoring and mitigation activities were completed.

1.3 Postaccident

1.3.1 Postaccident Geotechnical Assessment

Following the rupture, a contractor directed by the National Transportation Safety Board (NTSB) found that the area around the incident site was highly susceptible to landslides and determined that Line 10 was situated in past landslide deposits at the rupture location. The contractor concluded that Line 10 was installed within a landslide feature that was accelerating, causing a rapid increase in strain on the pipeline before the rupture. The contractor indicated that landslide acceleration in the 6 months before the rupture was likely driven by high levels of precipitation, pre-existing cracks in the soil, ground water movement along the pipeline trenches, and loading from grading activities.

1.3.2 Postaccident Metallurgical Testing and Tensile Strain Analysis

Other contractors directed by the NTSB evaluated the ruptured girth weld, removed and evaluated exemplar girth welds, and estimated the tensile strain demand and capacity. Two incomplete penetration and lack of root fusion defects were identified on the fracture face of the ruptured girth weld.⁸ One defect was about 7 inches long and 0.13 inches deep. The other defect was about 4.9 inches long and 0.10 inches deep.

The objective of the tensile strain demand analysis was to estimate the strain on the pipeline caused by land movement at the failure location. The results of the pre- and post-rupture tensile strain demand analyses are shown in Table 1. The analyses assessed overall performance and did not account for known defects.

⁸ (a) *Incomplete penetration defects* occur when the weld root is not completely filled. (b) *Lack of root fusion defects* occur when the weld fails to fuse one side of the joint in the root. (c) The *root* is the point at which the weld metal intersects the base metal and extends furthest into the weld joint.

Table 1. Estimated tensile strain demand

| Pipeline Configuration | Pre-Rupture Analyses (Enbridge) | Post-Rupture Analyses (NTSB Investigation) |
|-------------------------------|---|--|
| April 2018 | N/A | 1.8% |
| July 2019 | 0.6% | N/A |
| May 2020 | N/A | 3.0% |

Further, tensile strain capacity analysis was performed to determine the amount of strain that a pipe section with a representative girth weld could withstand. The tensile strain capacity was estimated by evaluating exemplar girth welds, fabricating and testing material property samples, and developing a finite element model. The model used to estimate tensile strain capacity explicitly included flaws found in the exemplar girth welds that were up to 4 inches in length. The estimated tensile strain capacity was between 1.3 percent and 2 percent.

1.3.3 Postaccident Actions

1.3.3.1 Enbridge

Enbridge issued several new procedures for managing geohazards, including for estimating tensile strain capacity, conducting multidisciplinary reviews, and determining appropriate response actions. Enbridge reported that the new procedures would result in a reduced tensile strain capacity threshold (0.5 percent) on Line 10 in the area where the rupture occurred, which, given the information available before the incident, would trigger a high-priority response action.⁹ Additionally, Enbridge acknowledged that the pre-rupture strain demand methodology may have underestimated the actual strain demand. Enbridge indicated that it would continue to work with its contractors to determine whether a different method with an appropriate level of conservatism should be applied.

1.3.3.2 Pipeline and Hazardous Materials Safety Administration

On June 1, 2020, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an amended Corrective Action Order to Enbridge that required corrective actions be taken with respect to Lines 10, 15 and 25 for failures on August 1,

⁹ The *high-priority response action* requires a site visit within 48 hours, site-specific monitoring plan within 30 days, immediate pressure reduction or shutdown, and drainage installation, if appropriate, for site-specific conditions.

2019, near Danville, Kentucky, and May 4, 2020, near Hillsboro, Kentucky.¹⁰ The order required Enbridge to reduce the operating pressure of the affected segment, review prior ILI results, and review and assess its emergency response plans, operations, and public awareness program. Further, on December 21, 2021, PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order to Enbridge alleging probable violations related to the Hillsboro accident.

On May 26, 2022, PHMSA issued an advisory bulletin, citing the Hillsboro accident among others, that reminds owners and operators of gas and hazardous liquid pipelines of the potential for damage to pipeline facilities caused by earth movement in variable, steep, and rugged terrain and for varied, changing subsurface geological conditions. The bulletin states that changing weather patterns, including increased rainfall and higher temperatures, can result in flooding, soil saturation, and erosion impacting soil stability surrounding pipeline facilities. PHMSA's advisory bulletin further lists pipeline safety actions operators should consider to ensure pipeline safety.¹¹

2. Analysis

In 2018, Enbridge identified the rupture location as a potential geohazard. They took action to analyze the active landslide and started taking steps to mitigate the hazard before the rupture. However, Enbridge's pre-rupture analysis estimated a girth weld tensile strain demand that was at least three times lower than post-rupture analysis later indicated. The post-rupture analysis demonstrated that in April 2018 or earlier Enbridge could have foreseen the likelihood that the tensile strain demand would exceed the strain capacity due to documented land movement at the site.

Like all analyses, tensile strain demand and capacity calculations include certain modeling assumptions and associated uncertainties that must be considered in any decision-making that relies on the results. Notably, Enbridge's pre-rupture analyses did not appropriately consider uncertainties such as weld defects, changes in the slope and direction of the landslide that could increase the susceptibility of the girth welds to fracture, acceleration of the landslide, or the response of the pipeline to these factors. As

¹⁰ The August 1, 2019, rupture that occurred near Danville, Kentucky, is currently under investigation by the NTSB. Additional information can be found in the public docket for NTSB investigations (number PLD19FR002) by accessing the NTSB [Dockets Link](#) at www.nts.gov.

¹¹ The suggested actions include, but are not limited to, monitoring geological and environmental conditions near facilities, including changing weather patterns; identifying areas surrounding pipelines that may be prone to large earth movement; developing design, construction, and monitoring plans and procedures and developing mitigation measures to remediate identified locations; and tracking changes in ground conditions. For more information, see *PHMSA Advisory Bulletin: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards*, <https://www.phmsa.dot.gov/news/phmsa-advisory-bulletin-potential-damage-pipeline-facilities-caused-earth-movement-and-other>.

a result, Enbridge determined that no immediate action was needed to mitigate the identified geohazard threat and therefore did not take necessary actions before the rupture.

As a result of this accident, Enbridge issued new procedures for estimating tensile strain capacity, conducting multidisciplinary reviews, and determining appropriate response actions, reporting the new procedures would result in a reduced tensile strain capacity threshold. Further, PHMSA took enforcement action against Enbridge. PHMSA also issued an advisory bulletin on damage to pipeline facilities from earth movement in rugged, steep terrain, citing the Hillsboro accident among recent land movement events.

3. Probable Cause

The National Transportation Safety Board determines that the probable cause of the pipeline rupture was Enbridge Inc.'s analysis of an active landslide that did not fully address uncertainties associated with pipeline defects, landslide movement, and corresponding pipeline response.

The National Transportation Safety Board (NTSB) is an independent federal agency dedicated to promoting aviation, railroad, highway, marine, and pipeline safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974, to investigate transportation accidents, determine the probable causes of the accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The NTSB makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

The NTSB does not assign fault or blame for an accident or incident; rather, as specified by NTSB regulation, "accident/incident investigations are fact-finding proceedings with no formal issues and no adverse parties ... and are not conducted for the purpose of determining the rights or liabilities of any person" (Title 49 *Code of Federal Regulations* section 831.4). Assignment of fault or legal liability is not relevant to the NTSB's statutory mission to improve transportation safety by investigating accidents and incidents and issuing safety recommendations. In addition, statutory language prohibits the admission into evidence or use of any part of an NTSB report related to an accident in a civil action for damages resulting from a matter mentioned in the report (Title 49 *United States Code* section 1154(b)).

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EXHIBIT BMC-58

Enbridge Incorporated
Hazardous Liquid Pipeline Rupture and Release
Marshall, Michigan
July 25, 2010



Accident Report

NTSB/PAR-12/01

PB2012-916501



**National
Transportation
Safety Board**

NTSB/PAR-12/01
PB2012-916501
Notation 8423
Adopted July 10, 2012

Pipeline Accident Report

Enbridge Incorporated
Hazardous Liquid Pipeline Rupture and Release
Marshall, Michigan
July 25, 2010



**National
Transportation
Safety Board**

490 L'Enfant Plaza, S.W.
Washington, D.C. 20594

National Transportation Safety Board. 2012. *Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010. Pipeline Accident Report NTSB/PAR-12/01. Washington, D.C.*

Abstract: On Sunday, July 25, 2010, at 5:58 p.m., eastern daylight time, a segment of a 30-inch-diameter pipeline (Line 6B), owned and operated by Enbridge Incorporated (Enbridge) ruptured in a wetland in Marshall, Michigan. The rupture occurred during the last stages of a planned shutdown and was not discovered or addressed for over 17 hours. During the time lapse, Enbridge twice pumped additional oil (81 percent of the total release) into Line 6B during two startups; the total release was estimated to be 843,444 gallons of crude oil. The oil saturated the surrounding wetlands and flowed into the Talmadge Creek and the Kalamazoo River. Local residents self-evacuated from their houses, and the environment was negatively affected. Cleanup efforts continue as of the adoption date of this report, with continuing costs exceeding \$767 million. About 320 people reported symptoms consistent with crude oil exposure. No fatalities were reported.

As a result of its investigation of this accident, the National Transportation Safety Board (NTSB) makes recommendations to the U.S. Secretary of Transportation, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Enbridge, the American Petroleum Institute, the Pipeline Research Council International, the International Association of Fire Chiefs, and the National Emergency Number Association. The NTSB also reiterates a previous recommendation to PHMSA.

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Acronyms and Abbreviations

| | |
|-------------|--|
| API | American Petroleum Institute |
| ASME | American Society of Mechanical Engineers |
| CAO | corrective action order |
| CEPA | Canadian Energy Pipeline Association |
| CFR | <i>Code of Federal Regulations</i> |
| CMT | commodity movement and tracking |
| Coast Guard | U.S. Coast Guard |
| CPM | computational pipeline monitoring |
| CRM | crew resource management |
| DOT | U.S. Department of Transportation |
| DSAW | double submerged arc welded |
| Enbridge | Enbridge Incorporated |
| EPA | U.S. Environmental Protection Agency |
| FAA | Federal Aviation Administration |
| FOSC | Federal on-scene coordinator |
| HCA | high consequence area |
| Line 6B | 30-inch-diameter accident pipeline |
| LPM | Line Pressure Management |
| MBS | Material Balance System |
| MFL | magnetic flux leakage |
| MOP | maximum operating pressure |
| MP | mile point |
| NEB | National Energy Board |

| | |
|--------|---|
| NOPV | Notice of Probable Violation |
| NRC | National Response Center |
| NTSB | National Transportation Safety Board |
| PAP | public awareness program |
| PAPERS | Public Awareness Program Effectiveness Research Survey |
| PG&E | Pacific Gas and Electric Company |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PII | PII Pipeline Solutions |
| PIPES | Pipeline Inspection, Protection, Enforcement and Safety |
| PLM | pipeline maintenance |
| PREP | Preparedness for Response Exercise Program |
| PS | pump station |
| psi | pounds per square inch |
| psig | pounds per square inch, gauge |
| RP | recommended practice |
| SCADA | supervisory control and data acquisition |
| SCC | stress corrosion cracking |
| SMS | safety management system |
| SMYS | specified minimum yield strength |
| TSB | Transportation Safety Board of Canada |
| USCD | UltraScan Crack Detection |
| USGS | U.S. Geological Survey |
| USWM | UltraScan Wall Measurement |
| Volpe | Volpe National Transportation Systems Center |

Executive Summary

On Sunday, July 25, 2010, at 5:58 p.m., eastern daylight time, a segment of a 30-inch-diameter pipeline (Line 6B), owned and operated by Enbridge Incorporated (Enbridge) ruptured in a wetland in Marshall, Michigan. The rupture occurred during the last stages of a planned shutdown and was not discovered or addressed for over 17 hours. During the time lapse, Enbridge twice pumped additional oil (81 percent of the total release) into Line 6B during two startups; the total release was estimated to be 843,444 gallons of crude oil. The oil saturated the surrounding wetlands and flowed into the Talmadge Creek and the Kalamazoo River. Local residents self-evacuated from their houses, and the environment was negatively affected. Cleanup efforts continue as of the adoption date of this report, with continuing costs exceeding \$767 million. About 320 people reported symptoms consistent with crude oil exposure. No fatalities were reported.

The National Transportation Safety Board (NTSB) determines that the probable cause of the pipeline rupture was corrosion fatigue cracks that grew and coalesced from crack and corrosion defects under disbanded polyethylene tape coating, producing a substantial crude oil release that went undetected by the control center for over 17 hours. The rupture and prolonged release were made possible by pervasive organizational failures at Enbridge Incorporated (Enbridge) that included the following:

- Deficient integrity management procedures, which allowed well-documented crack defects in corroded areas to propagate until the pipeline failed.
- Inadequate training of control center personnel, which allowed the rupture to remain undetected for 17 hours and through two startups of the pipeline.
- Insufficient public awareness and education, which allowed the release to continue for nearly 14 hours after the first notification of an odor to local emergency response agencies.

Contributing to the accident was the Pipeline and Hazardous Materials Safety Administration's (PHMSA) weak regulation for assessing and repairing crack indications, as well as PHMSA's ineffective oversight of pipeline integrity management programs, control center procedures, and public awareness.

Contributing to the severity of the environmental consequences were (1) Enbridge's failure to identify and ensure the availability of well-trained emergency responders with sufficient response resources, (2) PHMSA's lack of regulatory guidance for pipeline facility response planning, and (3) PHMSA's limited oversight of pipeline emergency preparedness that led to the approval of a deficient facility response plan.

Safety issues identified during this accident investigation include the following:

- **The inadequacy of Enbridge's integrity management program to accurately assess and remediate crack defects.** Enbridge's crack management program relied

on a single in-line inspection technology to identify and estimate crack sizes. Enbridge used the resulting inspection reports to perform engineering assessments without accounting for uncertainties associated with the data, tool, or interactions between cracks and corrosion. A 2005 Enbridge engineering assessment and the company's criteria for excavation and repair showed that six crack-like defects ranging in length from 9.3 to 51.6 inches were left in the pipeline, unrepaired, until the July 2010 rupture.

- **The failure of Enbridge's control center staff to recognize abnormal conditions related to ruptures.** Enbridge's leak detection and supervisory control and data acquisition systems generated alarms consistent with a ruptured pipeline on July 25 and July 26, 2010; however, the control center staff failed to recognize that the pipeline had ruptured until notified by an outside caller more than 17 hours later. During the July 25 shutdown, the control center staff attributed the alarms to the shutdown and interpreted them as indications of an incompletely filled pipeline (known as column separation). On July 26, the control center staff pumped additional oil into the rupture pipeline for about 1.5 hours during two startups. The control center staff received many more leak detection alarms and noted large differences between the amount of oil being pumped into the pipeline and the amount being delivered, but the staff continued to attribute these conditions to column separation. An Enbridge supervisor had granted the control center staff permission to start up the pipeline for a third time just before they were notified about the release.
- **The inadequacy of Enbridge's facility response plan to ensure adequate training of the first responders and sufficient emergency response resources allocated to respond to a worst-case release.** The first responders to the oil spill were four Enbridge employees from a local pipeline maintenance shop in Marshall, Michigan. Their efforts were focused downstream along the Talmadge Creek rather than near the immediate area of the rupture. The first responders neglected to use the culverts along the Talmadge Creek as underflow dams to minimize the spread of oil, and they deployed booms unsuitable for the fast-flowing waters. Further, the oil spill response contractors, identified in Enbridge's facility response plan, were unable to immediately deploy to the rupture site and were over 10 hours away.
- **Inadequate regulatory requirements and oversight of crack defects in pipelines.** Title 49 *Code of Federal Regulations* (CFR) 195.452(h) fails to provide clear requirements for performing an engineering assessment and remediation of crack-like defects on a pipeline. In the absence of prescriptive regulatory requirements, Enbridge applied its own methodology and margins of safety. Enbridge chose to use a lower margin of safety for cracks than for corrosion when assessing crack defects. PHMSA expects pipeline operators to excavate all crack features; however, PHMSA did not issue any findings about the methods used by Enbridge in previous inspections.
- **Inadequate regulatory requirements for facility response plans under 49 CFR 194.115, which do not mandate the amount of resources or recovery capacity required for a worst-case discharge.** In the absence of such requirements, Enbridge interpreted the level of oil response resources required under PHMSA's

three-tier response time frame, resulting in a lack of adequate oil spill recovery equipment and resources in the early hours of the first response. By contrast, the U.S. Coast Guard (Coast Guard) and the U.S. Environmental Protection Agency (EPA) regulations specify effective daily response capability for each of the three tiers for oil spill response planning.

- **PHMSA's inadequate review and approval of Enbridge's facility response plan that failed to verify that the plan content was accurate and timely for an estimated worst-case discharge of 1,111,152 gallons.** PHMSA's facility response program oversaw 450 facility response plans with 1.5 full-time employees, which is a lower staffing commitment than comparable response plan review programs carried out by the EPA and the Coast Guard. PHMSA and other Federal agencies receive funding from the Oil Spill Liability Trust Fund to cover operational, personnel, enforcement, and other related program costs.

As a result of this investigation, the NTSB makes safety recommendations to the U.S. Secretary of Transportation, PHMSA, Enbridge, the American Petroleum Institute, the Pipeline Research Council International, the International Association of Fire Chiefs, and the National Emergency Number Association. The NTSB also reiterates a previous recommendation to PHMSA.

1 Factual Information

1.1 Introduction

On Sunday, July 25, 2010, at 5:58 p.m., eastern daylight time,¹ a segment of a 30-inch-diameter pipeline (Line 6B), owned and operated by Enbridge Incorporated (Enbridge) ruptured in a wetland in Marshall, Michigan, about 0.6 mile downstream of the Marshall Pump Station (PS), releasing about 843,444 gallons of crude oil.² The accident pipeline was part of Enbridge's liquid pipeline system that originates in Edmonton, Alberta, Canada, and terminates in Sarnia, Ontario, Canada. The 1,900-mile U.S. portion, known as the Lakehead System, consists of pipelines of various diameters and ages operated from a control center in Edmonton. Line 6B is a 293-mile section of the Lakehead System, which crosses the state of Michigan joining Griffith, Indiana, to Sarnia. (See figure 1.)

Line 6B was installed in 1969 and constructed from 30-inch-diameter carbon steel pipe wrapped with a single layer of polyethylene tape. The ruptured pipe segment was manufactured to an American Petroleum Institute (API) Standard 5LX³ grade X52⁴ specification with a 0.25-inch wall thickness and a double submerged arc welded (DSAW) longitudinal seam; it was cathodically protected. Immediately prior to the accident, the highest recorded downstream pressure at the Marshall PS was 486 pounds per square inch, gauge (psig).⁵ During 2010, Line 6B transported about 11.9 million gallons of crude oil per day.

The rupture occurred in the final stages of a planned Line 6B shutdown that was scheduled to have the pipeline out of operation for 10 hours. The shutdown, started at 5:55 p.m., was performed in just a few minutes by shutting off pumps from the Griffith PS to the Marshall PS while increasing pressure at a pressure control valve that was downstream of the Marshall PS at the Stockbridge Terminal. (The shutdown, during which oil would not be pumped through the pipeline, had been planned to accommodate the oil delivery schedule at the Griffith Terminal.) About 1 minute after increasing the pressure at the Stockbridge Terminal, the pipeline ruptured downstream of the Marshall PS. Multiple alarms were immediately generated at the Enbridge control center following the rupture, but Enbridge staff believed the alarms

¹ All times in this report are eastern daylight time unless otherwise specified.

² Line 6B transports multiple grades of heavy bituminous crude oil from the oil sand regions of Western Canada that require dilution with lighter petroleum products to enable the crude to flow easier. For simplicity, this report will refer to the product in Line 6B as crude oil.

³ The API develops industry-based consensus standards that support oil and gas production and distribution. API 5LX is a specification for line pipe.

⁴ Grade X52 signifies that the pipe has a specified minimum yield strength (SMYS) of 52,000 pounds per square inch (psi). Yield strength is a measure of the pipe's material strength and indicates the stress level at which the material will exhibit permanent deformation. Although yield strength is expressed in psi, this value is not equivalent to a pipe's internal pressure.

⁵ Psig is a unit of measure for pressure expressed relative to pressure exerted by the surrounding atmosphere. Psi will be used in this report as a unit of measure for stress and is a measure of force acting over a given area.

resulted from a combination of column separation⁶ and erratic pressures generated during shutdown rather than a rupture.



Figure 1. Enbridge’s Liquids System and the 1,900-mile Lakehead System (the U.S. portion). Inset shows Line 6B, the 293-mile extension from Griffith to Sarnia installed in 1969.

To resume operations following the planned 10-hour shutdown, Enbridge staff started Line 6B once at 4:04 a.m. on July 26 and pumped oil for about 1 hour before shutting down the line. At 7:20 a.m., Enbridge staff started Line 6B again and pumped oil for about 30 minutes before shutting down the line. During the two startups and 1.5 hours of operation, Enbridge staff pumped about 683,436 gallons of oil⁷ (81 percent of the total release) into the ruptured pipeline without seeing an increase in the pressure. Leak-detection alarms were generated, but Enbridge staff continued to believe the alarms were the result of column separation, even though the Marshall area was relatively flat, without significant elevation changes. Enbridge staff also

⁶ *Column separation* is a condition indicating a mixture of liquid and vapor—a vapor bubble—exists in the pipeline. Column separation usually occurs at changes in elevation or where liquid does not completely fill the pipeline. The immediate area around the Marshall PS was relatively flat; however, a 100-foot elevation increase existed about 13 miles downstream. For more information about column separation, see section 1.11.5.4, “Column Separation,” of this report.

⁷ An NTSB study estimated this amount.

considered operational changes implemented before the startups, including a Niles PS shutdown and valve closure (due to an in-line crack inspection) and the possibility that large volumes of oil had settled into lower elevations and delivery locations, to be complicating factors.

The Calhoun County 911 dispatch center received the first call about odors associated with the oil release about 9:25 p.m. on July 25 (3.5 hours after the rupture) and dispatched firefighters from Marshall City; however, firefighters were unable to pinpoint a source of the odors. A gas utility worker, responding to the area because of numerous calls about gas odors, notified the Enbridge control center about oil on the ground at 11:17 a.m. on July 26 (more than 17 hours after the rupture). In less than 5 minutes, Enbridge staff began closing remote valves upstream and downstream of the rupture, sealing off the site within a 2.95-mile section.

The fracture in the ruptured segment measured 6 feet 8.25 inches long and up to 5.32 inches wide. (See figure 2.) External corrosion was present along the longitudinal weld seam and in areas where the adhesive bond between the pipe and its protective polyethylene tape coating had deteriorated (disbonded). The coating was wrinkled and had separated from the pipe surface as shown in the red circle in figure 2.



Figure 2. The ruptured segment of Line 6B in the trench following the July 25, 2010, rupture. The fracture face measured about 6 feet 8.25 inches long and was 5.32 inches wide at the widest opening. The fracture ran just below the seam weld that was oriented just below the 3 o'clock position. A red circle shows a location where the coating was wrinkled and had separated from the pipe surface.

The crude oil release soaked the rupture site and the surrounding wetlands, eventually spreading to the Talmadge Creek and the Kalamazoo River. Enbridge's early response efforts were focused downstream of the rupture. Recent heavy rainfall had increased the flow of the Talmadge Creek and the Kalamazoo River, which spread the oil faster, hindering the response efforts. (See figure 3.)

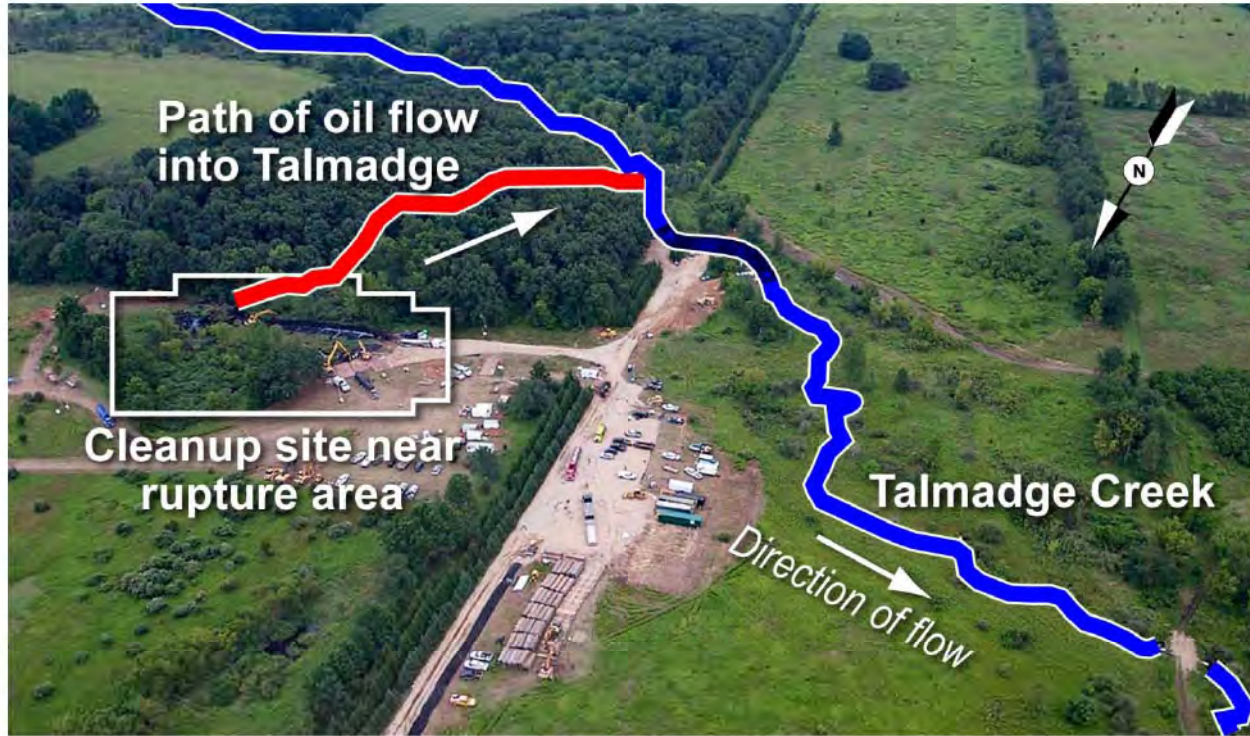


Figure 3. Aerial view of the accident location showing the rupture site to the left and the Talmadge Creek flowing west toward the Kalamazoo River.

The wetland conditions in addition to the crude oil release made it difficult for vacuum trucks and excavators to get near the rupture location. Large wooden matting had to be placed around the rupture location to bring heavy equipment close to the release. (See figure 4.) The conditions at the accident site also delayed efforts to extract the pipe and to contain the oil near the rupture source.



Figure 4. Cleanup efforts in an oil-soaked wetland near the rupture site. Saturated soil complicated the cleanup and excavation efforts. An excavator with a vacuum attachment is shown situated on wooden matting near the rupture site.

Figure 5 shows a timeline highlighting the accident events that spanned over 17 hours from the time of the rupture until the Enbridge control center was made aware of it. Figure 6 shows the key Enbridge staff involved.

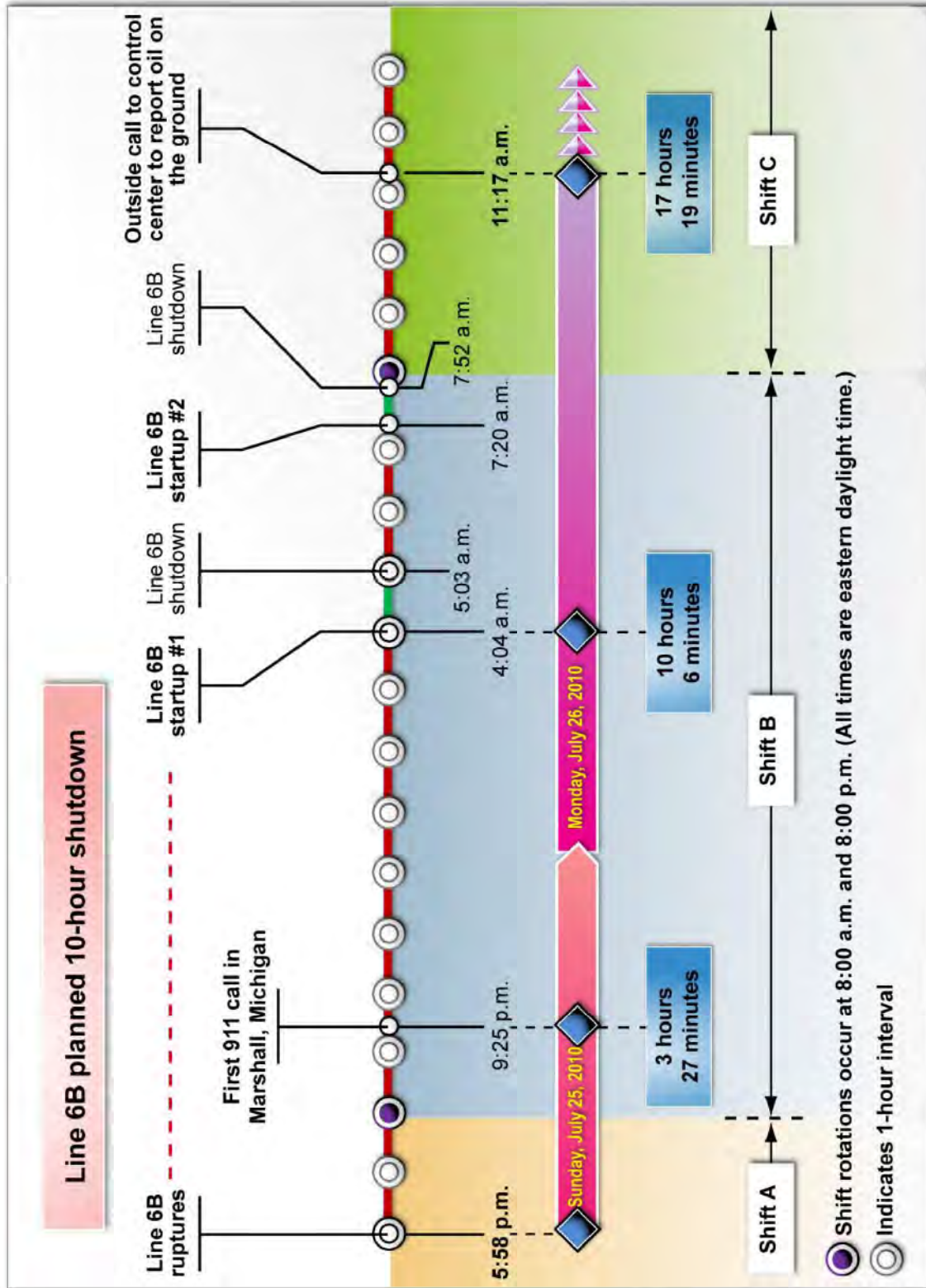


Figure 5. Key events timeline of the Line 6B rupture in Marshall, Michigan, showing the events from the time of rupture on July 25, 2010, to the time of discovery on July 26, 2010.

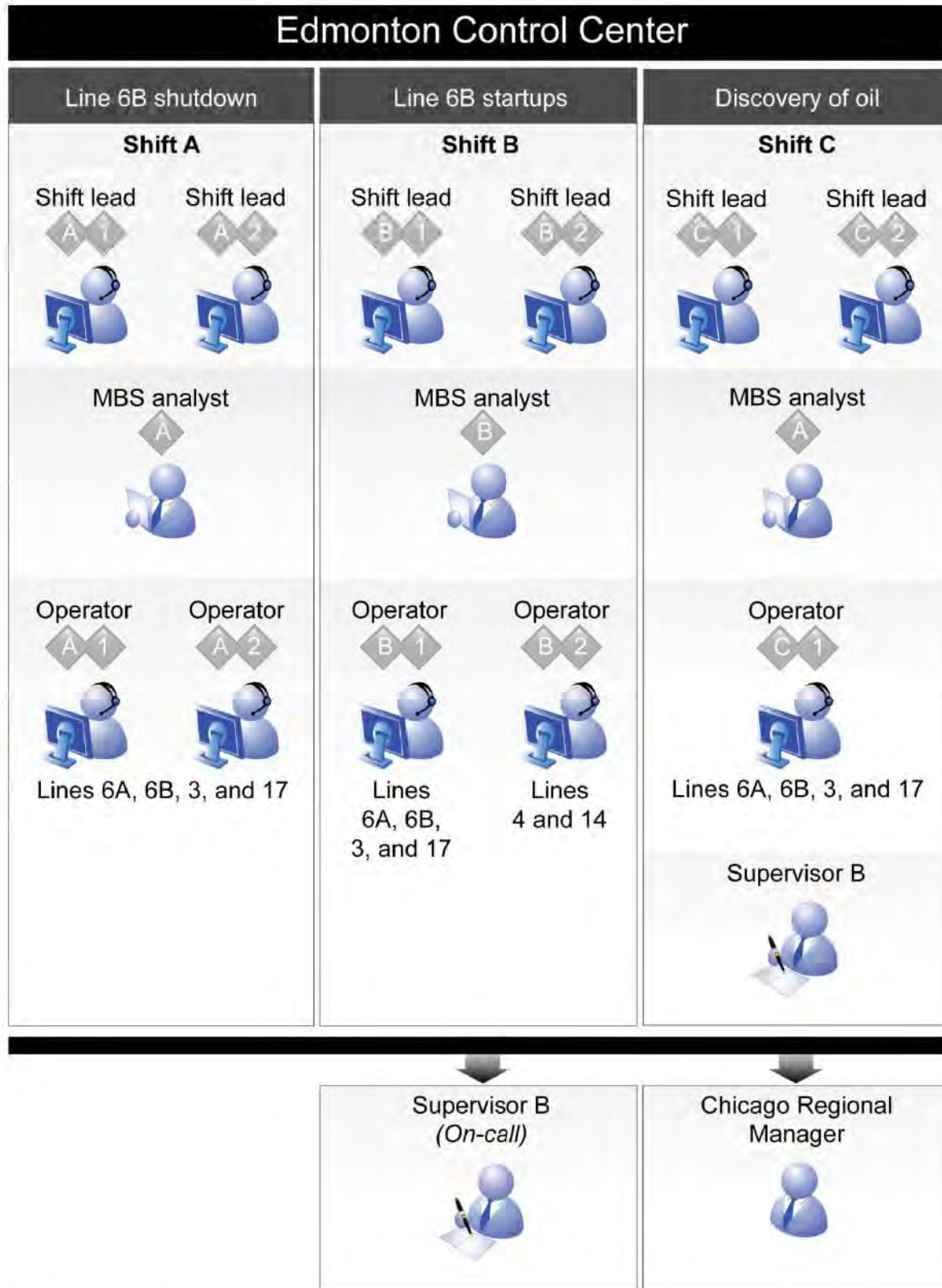


Figure 6. Key Enbridge staff involved in the 17-hour accident sequence. MBS refers to Material Balance System.

1.2 Accident Narrative

1.2.1 Preaccident Events

The planned shutdown of Line 6B was scheduled to begin following the last crude oil delivery to the Stockbridge Terminal, located downstream of the Marshall PS (see figure 7). A shutdown was to be performed by pipeline operator A1, sequentially, in the direction of flow, by turning off the pumps at the following PSs: Griffith, La Porte, Niles, Mendon, and Marshall. The shutdown was started at 5:55 p.m. by stopping two pumps at the Griffith PS and a pump at the La Porte PS. At 5:57 p.m., operator A1 increased the upstream pressure at a pressure control valve⁸ at the Stockbridge Terminal before stopping a pump at the Niles PS and a pump at the Mendon PS about 1 minute later.

1.2.2 The Rupture—Shift A

The rupture occurred on July 25, 2010, at 5:58 p.m. in the final minute of a planned Line 6B shutdown, about 45 seconds after operator A1^{9,10} increased upstream pressure (toward the Marshall PS) at a pressure control valve located at the Stockbridge Terminal and had stopped pumps at the Niles and the Mendon PSs. When the pipeline segment ruptured, the Marshall PS shut down automatically and three alarms almost simultaneously appeared on operator A1's supervisory control and data acquisition (SCADA) system display: an invalid-pressure¹¹ alarm (a severe alarm),¹² a low-suction-pressure alarm (a warning alarm),¹³ and a station local shutdown alarm¹⁴ (a warning alarm). The first two alarms cleared within 5 seconds but then reappeared because of the pressure changes resulting from the rupture. Within the same few seconds, operator A1 stopped the Marshall PS as part of the planned shutdown; he later told investigators that he had not recognized that a rupture had occurred. After the pipeline shut down, valves were closed at the Niles PS (see figure 7) to accommodate a Line 6B in-line inspection tool¹⁵ that had been launched the previous day.

⁸ Operator A1 increased the holding pressure from 50 to 200 psig at the Stockbridge Terminal pressure control valve (see appendix C for more information).

⁹ Operator A1 had 29 years of pipeline operator experience but was requalifying after a 6-month-long disability leave from the control center. During his requalification, a mentor was overseeing his work. The mentor (operator A2) had an equivalent amount of experience.

¹⁰ Control center operators were responsible for the operation of multiple pipelines and sometimes pipelines and terminals. The Line 6B operator (operator A1) was also responsible for Lines 3, 17, and 6A.

¹¹ This alarm was generated by the Line Pressure Management (LPM) system, which is designed to protect the pipeline from being overpressured.

¹² Enbridge defined a "severe alarm" as requiring the control center operator to notify the shift lead, advise the on-site/on-call staff, and create an entry in the facility maintenance database system.

¹³ Enbridge defined a "warning alarm" as discretionary operator response dependent on operating conditions. Multiple alarms can result in an increased severity.

¹⁴ These latter two alarms were generated by the Marshall PS.

¹⁵ A cleaning tool and an in-line crack inspection tool were launched on July 24 at the Griffith Terminal, separated by about 5 miles. They remained upstream of the Niles PS even after the oil release was identified. The tools remained in the pipeline until the failed section was replaced and Line 6B returned to service in September 2010.

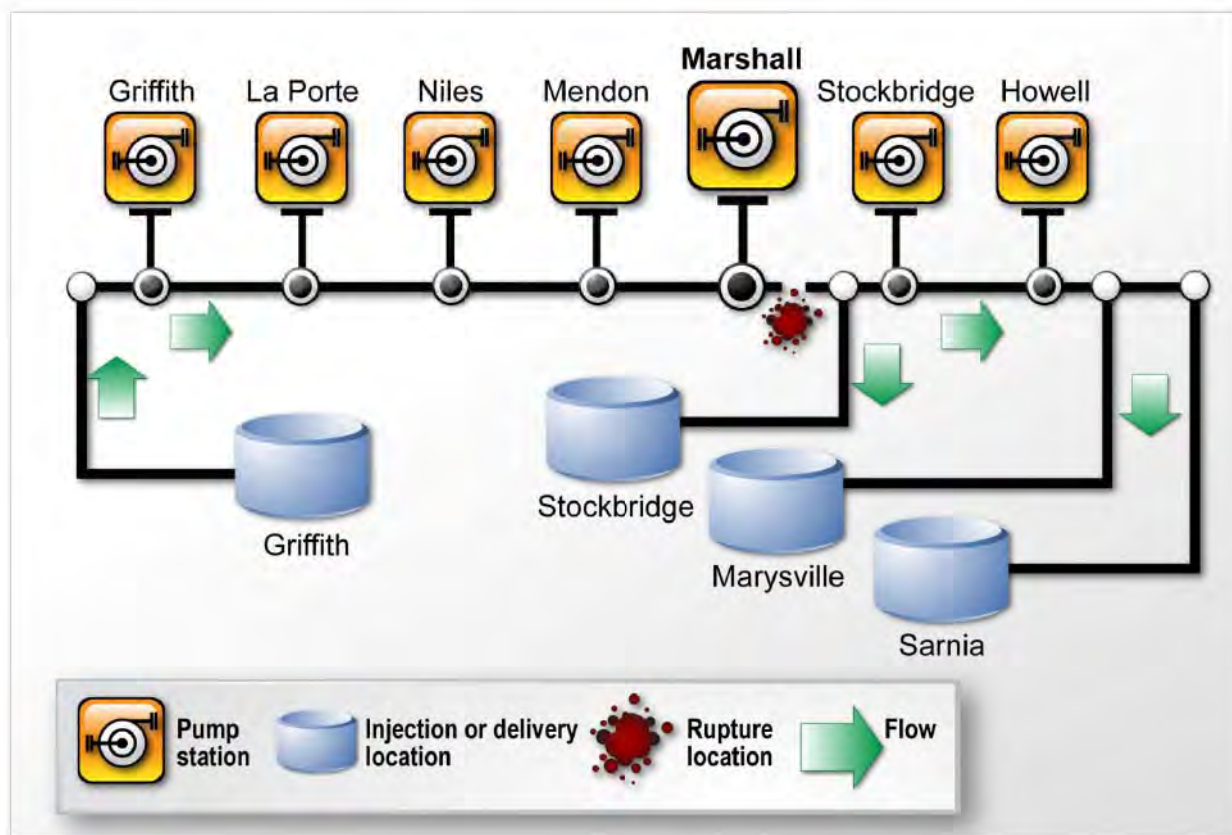


Figure 7. Simplified schematic of Line 6B, showing pump stations and delivery locations.

By 6:03 p.m., operator A1 had received several more alarms related to the Line 6B rupture, including a 5-minute Material Balance System (MBS) alarm¹⁶ (a severe leak alarm), another low-suction-pressure alarm, and six additional invalid-pressure alarms. (All of the alarms were indications of the rupture.) The 5-minute MBS alarm indicated that a large oil volume imbalance had been detected in the pipeline. Operator A1 informed shift lead A1 about the MBS alarm, and shift lead A1 contacted MBS analyst A about the MBS alarm.

At 6:05 p.m., MBS analyst A called operator A1 to explain that he had concluded column separation near the Marshall PS had generated the MBS alarm.

Within minutes, the MBS alarm cleared on its own. (MBS alarms clear after a shutdown because the oil flow stops.) About this time, MBS analyst A told shift lead A2 about the alarm, his conclusion about its suspected cause, and its status. There was no further discussion about the MBS alarm during the shift.

¹⁶ A single MBS alarm may be associated with multiple instances of column separation. MBS alarms display as 5-minute, 20-minute, or 2-hour alarms, indicating relative leak size. The 5-minute alarm represents the largest leak rate, and the 2-hour alarm represents the smallest leak rate.

Operators A1 and A2¹⁷ independently told National Transportation Safety Board (NTSB) investigators that when the MBS alarm had cleared, they were no longer concerned about the low pressure at the Marshall PS because they believed the alarms were related to column separation and the shutdown. Line 6B remained shut down¹⁸ for 10 hours, as scheduled. The Marshall PS pressures remained at zero.

1.2.3 First Line 6B Startup—Shift B

The Sunday second shift control center staff took over operations between 8:00 p.m. and 8:30 p.m.¹⁹ During shift rotations, a verbal exchange of operational information, known as a shift exchange, took place among the control center operators, MBS analysts, and the shift leads. At the time of the accident, Enbridge had a procedure that required specific information to be exchanged during shift changes, but no formal documentation or written record of the exchanged information was required.

Shift lead B1 told investigators that, during the shift exchange, he was not informed about the previous shutdown or the pending startup of Line 6B, the MBS alarm, or the in-line inspection tool in Line 6B. Operator B1²⁰ said that he was not informed about the alarms that occurred during the shutdown but that he had been told about the scheduled Line 6B startup, the in-line inspection, and the Niles PS valve closure for the in-line inspection. He stated that he expected the Line 6B startup would be difficult because of the Niles PS being shut down to accommodate the in-line inspection tool. This meant that the Niles PS pumps could not be operated and the pressures would be lower coming into the Mendon PS (upstream of the Marshall PS). He did not question the low pressures at the Marshall PS.

At 8:56 p.m., Michigan Gas Utilities dispatched a senior service technician to respond to a residential report of natural gas odor. At 9:25 p.m. on July 25, a local resident called the Calhoun County 911 dispatch center and stated the following:

I was just at the airport in Marshall and drove south on Old 27 [17 Mile Road] and drove back north again and there's a very, very, very strong odor, either natural gas or maybe crude oil or something, and because the wind's coming out of the north, you can smell it all the way up to the tanks, right across from where the airport's at, and then you can't smell it anymore.

By 9:32 p.m., the Marshall City Fire Department had been dispatched in response to the 9:25 p.m. call to 911. The 911 dispatcher told the responders there was a report of a bad smell of natural gas near the airport.

¹⁷ Operator A2 told investigators that she was working on special projects alongside operator A1 when the accident occurred. She said she was aware of the MBS alarm but not directly involved with handling it.

¹⁸ When Line 6B was shut down, valves upstream and downstream of the rupture were closed, isolating a 75-mile span of the line and the rupture site.

¹⁹ The control center work shifts were 12 hours.

²⁰ Operator B1 had about 3.5 years experience in the Edmonton control center as a pipeline operator. See table 3 for further information about control center staff experience.

Marshall City Fire Department personnel responded to the area near the airport and requested the Marshall Township Fire Department to respond as well. To find the source of the odor, fire department personnel investigated several pipeline facilities and industrial buildings around Division Drive and 17 Mile Road, using a combustible gas indicator²¹ to try to locate the origin of the odor. No combustibles were detected. The Michigan Gas Utilities senior service technician crossed paths with some of the fire department personnel also trying to locate the source; he found no evidence of a gas leak. The fire department personnel departed the scene at 10:54 p.m. to return to the station. At 11:33 p.m., an employee at a business called 911 to report a natural gas odor. The 911 dispatcher explained that the fire department had already responded to calls in the area, and no more personnel were dispatched.²² (See figure 8.)

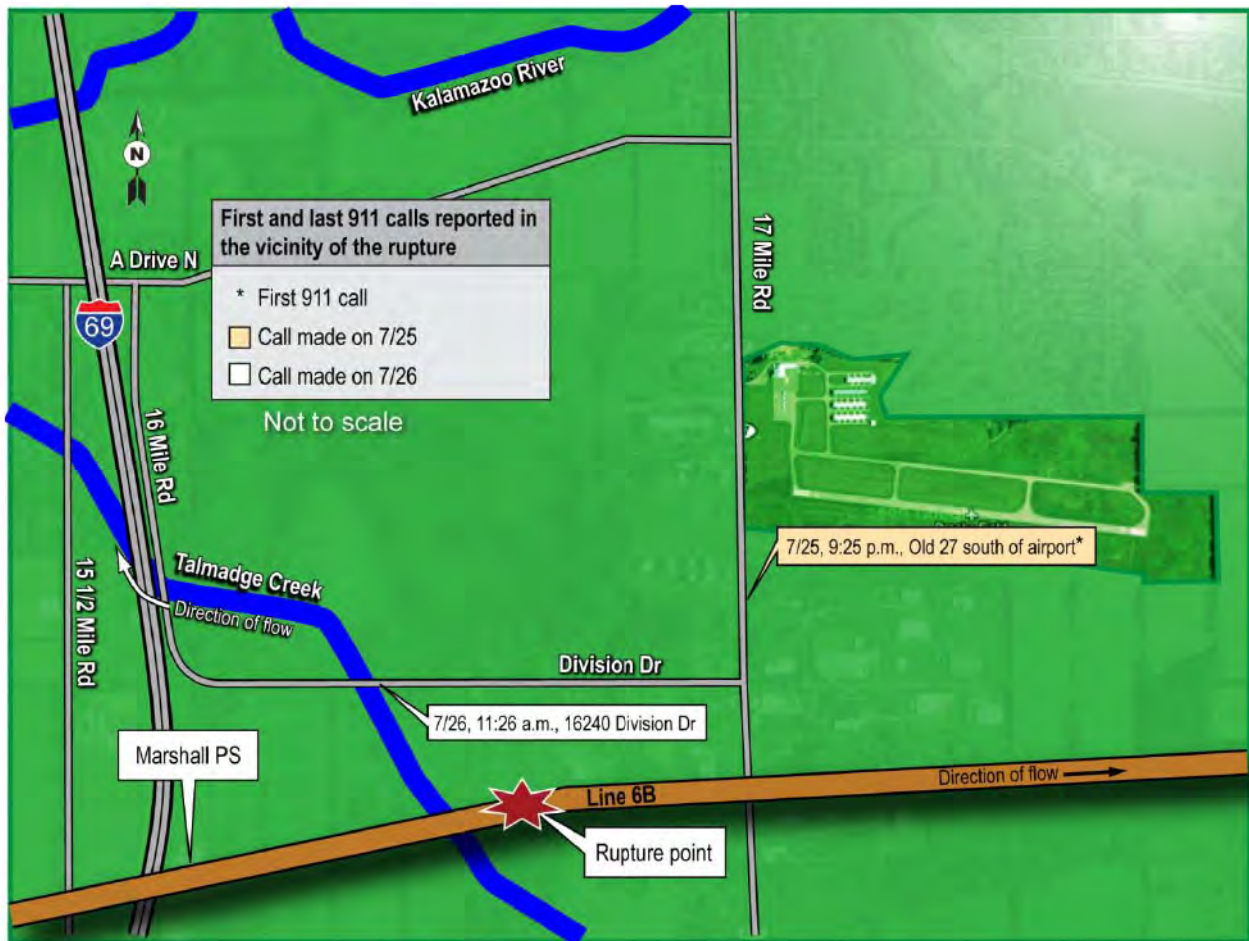


Figure 8. Emergency response and 911 calls from nearby residents. First and last calls are noted.

²¹ Because a combustible gas indicator measures percentage of the lower explosive limit, it likely would not detect the oil unless it was very close to the source.

²² Over the next 14 hours, the local 911 received seven more calls reporting strong natural gas or petroleum odors in the same vicinity. The 911 dispatcher repeatedly informed the callers that the fire department had been dispatched to investigate the reported odors.

On Monday, July 26, at 4:00 a.m., while preparing to start Line 6B for deliveries into the Marysville and Sarnia Terminals, operator B1 reduced pressure settings at two PSs (Marshall and Mendon) upstream of a valve that had lost communication.²³ Line 6B was going to be started without the Niles PS, which remained out of service for the in-line inspection tool.

About 4:04 a.m., operator B1 started Line 6B from the Griffith PS to the Mendon PS, and by 4:12 a.m., the first 5-minute MBS alarm appeared on his SCADA display. Operator B1 called MBS analyst B about the alarm. MBS analyst B told operator B1 that the alarm was due to column separation. After talking with operator B1, the MBS analyst realized that the MBS software had not been set up correctly²⁴ because the Niles PS valves were closed. According to MBS analyst B, the valve closure at the Niles PS might have resulted in additional column separation indications that morning.²⁵

By 4:24 a.m., operator B1 had received a 20-minute MBS alarm and another 5-minute MBS alarm. He notified shift lead B2 that Line 6B had been operating for 10 minutes but pressure remained less than 1 psig downstream of the Marshall PS. Enbridge's control center procedures required operators to shut down the pipeline when column separation could not be restored within 10 minutes.²⁶ Shift lead B2 and MBS analyst B told operator B1 to continue pumping oil to restore the column. Operator B1 started a larger pump upstream of the Marshall PS to increase the pipeline pressure.

During this time, operator B2²⁷ referred shift lead B1 to a draft column separation procedure that she had used earlier in the year. According to the draft procedure, when known column separation existed, an operator would calculate the time needed to fill the pipeline before starting the line. Once started, if column separation were present 10 minutes beyond the calculated time, the pipeline would be shut down. In effect, the draft procedure allowed the pipeline to operate in excess of the 10-minute limit under certain conditions. As operator B1 continued to pump additional oil into the pipeline, shift lead B1 attempted to estimate the time needed to restore the pressure downstream of the Marshall PS.²⁸ To do this, shift lead B1 tried to determine (1) the volume of oil that had settled throughout Line 6B during the shutdown and (2) the volume of oil that had drained into the Marysville Terminal during startup. Shift lead B1 estimated it would take about 20 minutes to bring the column back together.

²³ These were settings that protected the pipeline from overpressure in the event that the valve that had lost communication was closed.

²⁴ When the station valves at the Niles PS were closed to accommodate an in-line inspection tool, following the shutdown, the SCADA pressure transmitters used by the MBS were no longer using the real-time pipeline pressures, which resulted in errors in the MBS. To correct the MBS software, the MBS analyst had to override the pressures on both sides of the Niles PS. The MBS analyst stated that the lack of live pressures at the Niles PS may have affected the MBS alarms that morning.

²⁵ According to Enbridge, the software showed more instances of column separation before the software was adjusted.

²⁶ This duration was commonly referred to as the "10-minute rule" by the control center staff and represented the amount of time a pipeline was allowed to operate in instances of column separation or abnormal operations before being shut down.

²⁷ This was the shift mate of operator B1, who was operating Lines 4 and 14. Operator B2 had just over 2 years of experience as a pipeline operator. See table 3 for further information about control center staff experience.

²⁸ By dividing the amount of oil drained out into delivery locations during shutdown by gallons per hour, the shift lead can estimate how long the system must be run to restore pressure.

Operator B1 continued to start pumps on Line 6B and received multiple MBS alarms from 4:24 a.m. until 4:57 a.m. During this time, the Marshall PS discharge pressure never exceeded 3 psig. During this time when the Sarnia Terminal operator called operator B1 and remarked on the slow startup, operator B1 stated that “I’m just wondering either they really drained [Line 6B] out, which I think they did, because I don’t have any pressure farther down the line...Or else I’m—or else I’m leaking. One of the two.” Operator B1 called shift lead B1 about 5:00 a.m. to report that he had exceeded the estimated time to resolve the column separation issue. Operator B1 stated that the flow into the pipeline, upstream of the Marshall PS, was about 396,000 gallons per hour. After confirming with the Sarnia Terminal operator that only 71,062 gallons had been received since the startup, shift lead B1 instructed operator B1 to shut down Line 6B. About 5:03 a.m., Line 6B was shut down.

1.2.4 Second Line 6B Startup—Shift B

At 6:35 a.m., shift lead B2 called the on-call control center supervisor, and he then asked MBS analyst B to participate in the call. Shift lead B2 explained that they had been unable to resolve the column separation at the Marshall PS and that they had exceeded the estimated time needed to fill the pipeline. Shift lead B2 and the control center supervisor questioned MBS analyst B about the difference in pumped versus received volume. MBS analyst B explained that because of what he believed to be the severe column separation, the oil was filling the line rather than flowing through it to the delivery location.

The control center on-call supervisor stated that there were two choices: identify the alarms as a leak or identify the alarms as column separation and try to restart the pipeline again. Shift lead B2 asked MBS analyst B whether the MBS alarm was valid or invalid. MBS analyst B told shift lead B2 that the alarm was “false” because the MBS software was unreliable when column separation was present. The control center supervisor told shift lead B2, “To me it sounds like you need to try again and monitor it. Like [MBS analyst B] said, do it over again.”

About 7:09 a.m., operator B1 notified the Sarnia Terminal²⁹ operator that they were going to start Line 6B for a second time. The Sarnia Terminal operator expressed disbelief at the idea of a second startup. He told investigators that he had voiced his concerns about a Line 6B leak to shift leads B1 and B2 and MBS analyst B that morning. He stated that MBS analyst B had dismissed his concerns and, because he was dealing with other issues that morning, he had not pursued the matter.

Line 6B was started a second time about 7:20 a.m. By 7:36 a.m., as the Marshall PS discharge pressure started to increase, the first 5-minute MBS alarm appeared, followed by a 20-minute MBS alarm. Many additional 5-minute and 20-minute MBS alarms subsequently appeared through 7:42 a.m. During this time, operator B1 unsuccessfully attempted to start additional Line 6B pumps at the La Porte PS; the Marshall PS downstream pressure never increased above 4 psig. After shutting down Line 6B at 7:52 a.m., just before ending his shift, operator B1 made the following comment to the Sarnia Terminal operator.

²⁹ Because Line 6B was delivering oil into the Sarnia Terminal, the Sarnia Terminal operator was involved in the startup, opening valves and moving oil into the terminal tanks. The Sarnia Terminal operator stated that he was able to watch the Line 6B operation on his SCADA display.

I've never seen this...and to me like it looks like a leak...like I've never ever heard of that where you can't get enough—I can pump as hard as I want and I—I'd never over pressure the line. I don't know. Something about this feels wrong.

1.2.5 Discovery—Shift C

The shift C rotation occurred between 8:00 a.m. and 8:30 a.m. on Monday morning, July 26. The shift staff included the control center supervisor, who had been contacted during shift B while on call, and MBS analyst A, who had been on duty when the rupture occurred. During the shift exchange, shift leads C1 and C2 were informed about the presumed Line 6B column separation. Shift leads C1 and C2 called the control center supervisor to discuss the column separation issue.

Operator C1 told investigators that he had questioned the volume loss information during the shift exchange. By 8:46 a.m., operator C1 explained to shift leads C1 and C2 that in the past he had started Line 6B using every other PS and without operating the Niles PS. Operator C1 told investigators that he had reviewed SCADA data from the previous shifts that morning, saw the large pressure drop at the Marshall PS during the shift A shutdown, and immediately notified shift lead C1.

At 10:16 a.m., acting on the findings from operator C1 and discussions with shift lead C1, shift lead C2 called and asked the Chicago regional manager whether to send someone to walk along the pipeline, upstream and downstream of the Marshall PS. The Chicago regional manager replied, "I wouldn't think so. If it's right at Marshall—you know, it seems like there's something else going wrong either with the computer or with the instrumentation. ...you lost column and things go haywire, right?" He went on to say, "...I'm not convinced. We haven't had any phone calls. I mean it's perfect weather out here—if it's a rupture someone's going to notice that, you know and smell it." The Chicago regional manager told shift lead C1 that he was okay with the control center starting Line 6B again.

At 11:17 a.m., the control center was notified about the rupture via its emergency line. The caller said, "I work for Consumers Energy^{30]} and I'm in Marshall. There's oil getting into the creek and I believe it's from your pipeline. I mean there's a lot. We're getting like 20 gas leak calls and everything." Remote valves were closed at 11:18 a.m., sealing off the rupture site within a 2.95-mile section. By 11:20 a.m., the shift lead had called the Chicago regional manager to tell him about the notification. By 11:37 a.m., another Consumers Energy employee notified 911 about the crude oil leak in a creek near Division Drive. The Fredonia Township Fire Department was dispatched by the 911 center shortly after the call. At 11:41 a.m., the Edmonton control center received confirmation from an Enbridge crossing coordinator located at the Marshall pipeline maintenance (PLM) shop confirming the oil on the ground.

³⁰ Consumers Energy is an electric and gas utility provider with services in Calhoun County and Marshall, Michigan.

1.2.6 Enbridge Initial Response

At 11:45 a.m. on July 26, the initial Enbridge personnel at the accident location included the Marshall PLM shop crossing coordinator, an electrician, and two senior pipeline employees. After confirming the presence of oil near the ruptured pipeline, the crossing coordinator followed Talmadge Creek downstream to determine the extent of the oil discharge. He found that the oil had not migrated past A Drive North, about 1.5 miles downstream of the rupture, but he observed a large amount of oil at a creek crossing on 15 1/2 Mile Road, about 1 mile downstream of the rupture.

The four-person crew returned to the Marshall PLM shop and retrieved a vacuum truck, a work truck, a semi-truck, and an oil boom trailer. About 12:10 p.m., they returned to A Drive North and installed a double 20-foot length of sorbent boom across Talmadge Creek, where they observed only a little oil flowing. They also installed 20-foot lengths of sorbent boom across Talmadge Creek upstream of A Drive North and at a culvert on the south side of A Drive North. The Enbridge crossing coordinator told NTSB investigators that the Marshall PLM crew was not aware of the severity of the oil spill when it used these initial oil containment measures. The Enbridge first responders did not have an estimate of released volumes when they began their efforts to contain the oil. (See figure 9 for a map of the area around the rupture site where response efforts began.)



Figure 9. Area between rupture site and the Kalamazoo River where first responders concentrated efforts to contain the released oil.

About 12:30 p.m., the Marshall PLM crew moved upstream to the 15 1/2-Mile Road crossing of Talmadge Creek. The crew installed a 40-foot containment boom and sections of

sorbent boom on the upstream side of the culvert and spent the remainder of the day, until 11:00 p.m., using the Marshall PLM vacuum truck and skimmer to recover oil.

The Enbridge Bay City PLM supervisor (the interim incident commander until the Chicago regional manager arrived on site) told NTSB investigators that upon his arrival about 12:46 p.m., he observed an oily mixture discharging at a high rate through a 48-inch-diameter steel culvert pipe under Division Drive and continuing downstream in Talmadge Creek. He said the bulk of the released oil was contained upstream (south) of Division Drive. The supervisor stated that he considered having the culvert pipe plugged with earth; however, the water flow was too strong to enable him to do that.

About 1:30 p.m., the Marshall PLM supervisor arrived on scene and conferred with the Bay City PLM supervisor. They decided that the Marshall PLM supervisor would focus on stopping the leak source while the Bay City PLM supervisor would focus on installing oil boom at downstream locations ahead of the advancing oil. The National Response Center (NRC) was notified of the release about this same time on July 26. The NRC notified 16 Federal and state agencies about the spill.

About 2:45 p.m., the Bay City PLM supervisor worked with the Battle Creek Fire Department hazardous materials chief to locate an area for deploying boom for recovering the oil. About 15 minutes later, an Enbridge vacuum truck from the Bay City PLM shop began skimming oil from the water surface near Division Drive.

Between 4:30 and 6:30 p.m., four oil storage tanks were delivered to the Marshall PLM shop to temporarily store the oil that was being collected by the vacuum trucks. The Bay City PLM supervisor estimated that a total of 14 Enbridge personnel and between 6 and 10 personnel from Terra Contracting and Baker Corporation (contractors contacted by the incident commander for oil recovery and storage equipment) were working on scene to contain the oil during this time. The first U.S. Environmental Protection Agency (EPA) on-scene coordinator arrived in Marshall to assess the extent of the spill into Talmadge Creek about 4:32 p.m. The Marshall PLM shop was used as the incident command center.

Working with a six-person crew, the Marshall PLM supervisor constructed an earthen underflow dam, which consists of a mound of soil holding back oil-contaminated water with pipes submerged on the dam side and rising toward the discharge end. The angle of the pipe allows the deeper water in the dam to flow downstream, preventing the contaminated surface waters from flowing into Talmadge Creek. (See figure 10.)



Figure 10. Underflow dam on Talmadge Creek on July 30, 2010.

However, the crew found the width of the marsh too great and the ground too soft to construct an earthen dam near the source; instead the crew constructed a gravel-and-earth underflow dam at the confluence of the contaminated marsh and Talmadge Creek, which was accessible by heavy equipment. Enbridge crews used sections of 12-inch-diameter surplus polyvinyl chloride pipe they had found at the Marshall PLM shop to construct the underflow dam. Enbridge crews had learned of this oil containment strategy from participating in drills and exercises; this dam was the first they created during an actual emergency response. The heavy-equipment operators encountered significant difficulty because of the muddy conditions and the high-water flows. The construction of the first underflow dam began early in the afternoon on July 26, but it was not functional until 9:00 p.m. that evening. Crews had to tow the vacuum trucks through the mud to the underflow dam site and to the oily marsh locations until the first gravel roadway was constructed. The Marshall PLM supervisor told NTSB investigators that a considerable volume of oil was present in Talmadge Creek between the first underflow dam that Enbridge constructed and Division Drive. On July 26, Enbridge also deployed at least 12 vacuum trucks to begin recovering oil from the source area underflow dam, the Talmadge Creek stream crossings on Division Drive and 15 1/2 Mile Road, and from the Kalamazoo River at Calhoun County Historic Bridge Park (referred to as Heritage Park).³¹

³¹ The two initial EPA on-scene coordinators noted that only five vacuum trucks were operating on July 26, while seven additional vacuum trucks that were ordered did not arrive on site until July 27.

Additional contractors would not arrive until the following day to continue a larger scale oil response effort.

1.3 Injuries and Evacuations

1.3.1 Injuries

No immediate injury reports were made as a result of the Marshall release. The Michigan Department of Community Health conducted a followup study and issued its results in a November 2010 report titled *Acute Effects of the Enbridge Oil Spill*. The study was based on four community surveys along the affected waterways, 147 health care provider reports on 145 patients, and 41 calls placed to the poison center. The study identified 320 people and an additional 11 worksite employees who reported experiencing adverse health effects. Headache, nausea, and respiratory effects were the most common symptoms reported by exposed individuals. The report concluded that these symptoms were consistent with the published literature regarding potential health effects associated with crude oil exposure, which include irritation to the eyes, nose, and throat, as well as dizziness and drowsiness. Contact with the skin and eyes may also cause irritation or burns.

1.3.2 Evacuations

On July 26, the residents of six houses self-evacuated because of odors associated with the oil spill. On July 29, an EPA contractor produced a map outlining the recommended evacuation area, which extended from the spill area north and northwest to the Kalamazoo River, beyond the 15 Mile Road bridge crossing, and included 61 houses.³² The Calhoun County Public Health Department issued a voluntary evacuation notice to about 50 houses. The health department developed residential evacuation recommendations based on the concentration of benzene in the air. Benzene is a toxic constituent of crude oil that can cause drowsiness, dizziness, and unconsciousness. Long-term exposure to benzene causes effects on bone marrow and can cause anemia and leukemia. On August 12, the recommended evacuation of houses near the oil spill site was lifted after the benzene concentrations in the air were below the levels requiring evacuation.

1.4 Damages

1.4.1 Pipeline

The *Enbridge Inc. 2010 Annual Report* listed revenue losses for the Line 6B accident at \$13.2 million. Enbridge has stated that the cost to replace the 50-foot section of Line 6B was \$2.7 million.

³² See “Emergency and Environmental Response Attachment 39—Recommended Evacuation Zone Map,” in the NTSB public docket for this accident.

1.4.2 Environment

Enbridge's estimated costs for emergency response equipment, resources, personnel, and professional and regulatory support in connection with the cleanup of oil discharged from Line 6B were about \$767 million as of October 31, 2011.³³ This figure also encompasses the estimated cost of the Federal government's role in the cleanup, including employing contractors, which was an estimated \$42 million.

1.5 Environmental Conditions

1.5.1 Meteorological

The National Weather Service data recorded from Brooks Field Airport, Marshall, Michigan, at 5:55 p.m. near the time of the rupture showed the wind was from 10° at 4 knots, with good visibility and clear skies, the temperature was 79° F, and the dew point was 59° F. A light to moderate rain had occurred on the morning of July 24. On July 25, skies were clearing during the afternoon and evening hours, the high temperature was 79° F, and the low temperature was 69° F.

Weather reports from the W.K. Kellogg Airport, Battle Creek, Michigan, about 13 miles west of Marshall, reported rainfall amounts of about 2.4 inches on July 22 and July 23, 0.6 inch on July 24, and 1.37 inches on July 25.

1.5.2 Kalamazoo River Conditions

On July 26 at 12:45 p.m., the U.S. Geological Survey (USGS) reported the Kalamazoo River level in Marshall, Michigan, was 7.19 feet. Within 24 hours, the river level fell below 6 feet. The established flood state for this location is 8 feet. The USGS gauging station on the Kalamazoo River in Marshall, Michigan, reported the average current velocity at 1.44 mph.

1.6 Pipeline Information

1.6.1 Pipeline History

Enbridge documentation showed that the ruptured pipe segment was part of a purchase of 30-inch pipe from Siderius Inc. of New York on November 14, 1968, which was manufactured by Italsider s.p.a.³⁴ An inspection report dated March 18, 1969, noted that the chemical analysis and mechanical tests met the requirements of API and Enbridge specifications. Upon fabrication, the pipe was shipped bare from the Italsider s.p.a. facility located in Taranto, Italy, to the Port of Windsor, Ontario, and was delivered by truck to staging sites within Michigan. According to Enbridge, a field-applied spiral wrap of polyethylene tape coating was put on the pipe by machine at the time of Line 6B's construction.

³³ This was the most recent figure available at the time of this report.

³⁴ S.p.a. refers to Societa Per Azioni, a joint stock company with shareholders.

The ruptured segment was tested hydrostatically on November 21, 1969. No leaks or ruptures were documented. The certification letter, from the hydrostatic testing contractor, dated February 3, 1970, indicated that the ruptured segment had been tested to a minimum pressure of 783 psig and a maximum pressure of 820 psig for a 24-hour period. Enbridge used 796 psig as the hydrostatic test pressure of the ruptured segment in the integrity management assessments. The SMYS³⁵ of the ruptured segment was about 867 psig.

1.6.2 Pipeline Operating Pressure

The pipeline segment that ruptured had a maximum operating pressure (MOP) of 624 psig. However, the Marshall PS downstream pressure was limited to 523 psig at the time of the accident based on defects identified during a 2007 in-line inspection for corrosion (these features did not contribute to the rupture) of Line 6B. Historical pressure trends show that the Marshall PS was operating at 624 psig until 2004 when Enbridge imposed a 525 psig pressure restriction. No pressures in excess of 532 psig were noted from 2005 up until the time of rupture. Based on the SCADA pressures readings at the time of the rupture, the highest recorded discharge pressure at the Marshall PS, immediately preceding the rupture, was 486 psig. (See appendix C).

1.6.3 Site Description

The ruptured segment was buried about 5 feet below the ground surface and located 0.60 mile downstream from the Marshall PS. The rupture and release occurred in a wetland area near mile point (MP) 608.22 in Marshall, Michigan. The wetlands were located in an undeveloped, mostly rural area about 0.4 mile west of 17 Mile Road and about 0.2 mile south of Division Drive. Industrial complexes were located north and west along 17 Mile Road, less than 1 mile from the rupture site. The ruptured segment of Line 6B was operating in a high consequence area (HCA) identified as an “other populated area,” which is defined at Title 49 *Code of Federal Regulations* (CFR) 195.450(3) as a place “that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.”

1.6.4 Other Enbridge Pipeline Incidents

In 49 CFR 195.50, the Pipeline and Hazardous Materials Safety Administration (PHMSA) requires that pipeline operators submit an accident report for hazardous liquid releases, not related to a maintenance activity, that are 5 gallons or more and resulting in \$50,000 property damage, explosion, or fire. PHMSA publishes the summaries from these reports on its website.³⁶ The PHMSA incident and accident statistics for liquid transmission onshore crude oil releases sorted by volume from 1986 through 2011 show that Enbridge releases represent the second and fifth largest crude oil spills and that the company is included in

³⁵ The SMYS is the internal pressure that produces a calculated hoop stress equivalent to the minimum yield strength of the material assuming a nominal wall thickness and outside diameter.

³⁶ Information obtained from PHMSA’s website <<http://phmsa.dot.gov/pipeline/library/data-stats>> (accessed June 5, 2012).

3³⁷ of the top 15 releases. The NTSB³⁸ and the Transportation Safety Board of Canada (TSB) have investigated previous Enbridge leaks and ruptures that resulted from defects not remediated through the Enbridge integrity management program.

1.6.4.1 Cohasset, Minnesota

In 2004, the NTSB issued a report on an Enbridge failure that occurred on July 4, 2002, when Enbridge experienced a rupture and 252,000-gallon oil release on its Line 4, near Cohasset, Minnesota.³⁹ The fractured segment was a United States Steel tape-coated 34-inch-diameter API Standard 5LX grade X52 DSAW pipe with 0.312-inch wall thickness, installed in 1967. Examination of the failed pipe revealed a 13-inch-long transportation-induced metal fatigue⁴⁰ crack that had initiated from the internal surface of the pipe at multiple regions where the longitudinal seam weld intersected with the body of the pipe. The ruptured segment had been hydrostatically pressure tested in 1991 to 1,002 psig, and in-line inspections had been conducted twice in 1995 and once in 1996. Neither in-line inspection identified the fatigue crack that eventually grew to failure under repeated pressure cycling. Following the Cohasset accident, a PII (PII Pipeline Solutions) review of the data found that the 1996 inspection data did not meet the reporting criteria used by the PII analysts at the time and there had been problems with the in-line inspection tool. Examination of the 1995 tool runs revealed that the data quality issues prevented any detection of the crack that led to the eventual failure of the pipeline.

At the time of the NTSB investigation into the Cohasset accident, Enbridge stated that it had just introduced the more sophisticated UltraScan Crack Detection (USCD) inspection tool in the United States in 2001. In addition, Enbridge prepared a pipeline inspection procedure that called for “the excavation of all crack-like indications unless an engineering assessment determines that either the indication is acceptable based on a fitness-for-purpose calculation....” Enbridge analyzed crack growth rates using information from the 2002 failure in Cohasset to develop the worst-case scenario crack and its predicted time to failure. Based on these findings, Enbridge proposed to the Research and Special Programs Administration, the predecessor of PHMSA, that a portion of Line 4 be reinspected using the new in-line inspection technology at intervals of 3 years.

³⁷ Onshore, crude oil releases attributed to Enbridge are Grand Rapids, Minnesota, 1.7 million gallons; Pembina, North Dakota, 1.3 million gallons; Marshall, Michigan, 0.8 million gallons.

³⁸ At the time of this report, the NTSB is also investigating a release from Enbridge’s Line 6A that occurred on September 9, 2010, in Romeoville, Illinois. The release is estimated at 316,596 gallons of crude oil. Line 6A is a 34-inch-diameter pipeline with 0.281-inch wall thickness. It was constructed in 1968 and protected with a polyethylene tape coating. The pipe was manufactured by A.O. Smith Corp. with a flash welded longitudinal seam, manufactured to API Standard 5LX grade X52.

³⁹ *Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota, July 4, 2002*, Pipeline Accident Report NTSB/PAR-04/01 (Washington, D.C.: National Transportation Safety Board, 2004).

⁴⁰ *Transportation-induced metal fatigue* is a failure mechanism for pipe transported primarily by railroad and has also been associated with marine transportation. This type of fatigue is found along the longitudinal seam weld of the pipe and is caused by the cyclic stresses imposed during transportation as the pipe is subjected to frequent motion.

1.6.4.2 Glenavon, Saskatchewan

The TSB investigated a rupture involving Enbridge's Line 3 near Glenavon, Saskatchewan,⁴¹ that resulted in a release of nearly 200,000 gallons of crude oil on April 15, 2007. The pipeline was installed in 1968. It was manufactured to the 1967 API 5LX grade X52 specification with 0.28-inch wall thickness and a DSAW longitudinal seam. The pipe was originally protected with a polyethylene tape wrap coating and had an MOP of 652 psi. The TSB noted in its findings that the coating had tented⁴² over the longitudinal seam weld, exposing it to a corrosive environment. The rupture was caused by cracking that had initiated at a shallow area of corrosion (a corrosion groove) on the external surface of the pipe with a depth of less than 0.016 inch (5 percent of the wall thickness) where the external longitudinal seam weld intersected with the body of the pipe and had propagated by fatigue up to a depth of 0.112 inch (40 percent of the wall thickness) through the pipe wall. The Enbridge integrity management program did not identify this defect for excavation following an engineering assessment of the defect after the last in-line inspection was conducted in 2006, 1 year before the rupture.

According to the TSB's report findings:

The verification procedure used by Enbridge was to compare [in-line inspection] estimated crack sizes, and associated calculated failure pressures, with results obtained in the field by non-destructive ultrasonic inspection or crack grinding, or a combination of the two. Enbridge considers field and [in-line inspection] data to be sufficiently accurate if the data falls within an error band of plus or minus 10 percent.

The TSB's report also raised several issues regarding the quality of the inspection results and the analysis:

- In 2005, although Enbridge recalculated the crack growth rate to reflect the more aggressive pressure cycles, the parameters Enbridge used during that analysis did not accurately reflect the actual crack growth rate.
- The analysis of the 2006 in-line inspection data underestimated the depth of the deepest section of the fatigue crack.

The TSB determined that "The accuracy of the predictions of the crack growth model depends on the accuracy of the input parameters, including initial crack size. If any of these parameters have been underestimated, actual crack growth rates will exceed predicted values." The TSB stated the following:

When input parameters for the modeling of crack growth rates do not reflect probabilities and tolerances associated with the detection and sizing capabilities of [in-line inspection] ultrasonic crack detection tools as well as actual pipe conditions, actual crack growth rates may exceed estimated values.

⁴¹ Transportation Safety Board of Canada, *Crude Oil Pipeline Rupture, Enbridge Pipelines Inc. Line 3, Mile Post 506.2217, Near Glenavon, Saskatchewan, 15 April 2007*, Pipeline Investigative Report P07H0014.

⁴² See section 1.7.1, "Coating," of this report for further information about tenting.

1.7 Examination of the Accident Pipe

The ruptured pipe segment was 39 feet 10.75 inches long. The longitudinal seam was oriented at 99.5° clockwise.⁴³ A 50-foot length of pipe that included the rupture was removed and cut into two sections for shipping to the NTSB’s Materials Laboratory for examination. The upstream section measured 23 feet 4 inches. The downstream section measured 26 feet 10.25 inches. (See figure 11.)

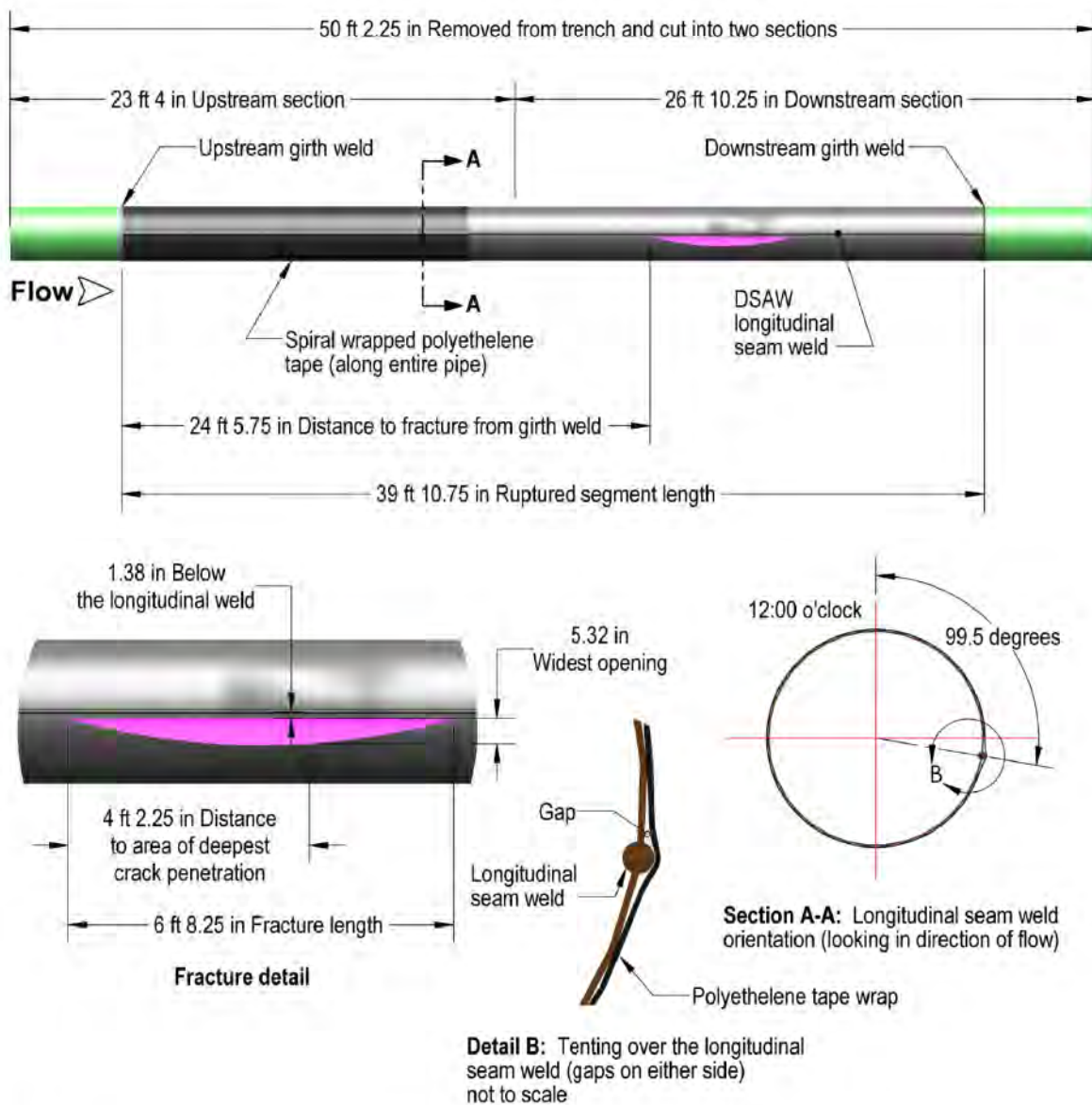


Figure 11. Line 6B ruptured segment showing upstream and downstream sections used for Materials Laboratory examination. Detail B shows tented coating over the longitudinal seam weld.

⁴³ Clockwise means as viewed facing the direction of flow. The top of the pipe is 0°, or the 12 o’clock position.

1.7.1 Coating

The ruptured segment was coated with a single wrap of Polyken 960-13 polyethylene tape with an adhesive backing. Enbridge reported that the tape coating had been applied in the field by a machine using Polyken 919 primer on the pipe. Examination revealed longitudinally oriented wrinkles in the coating, mostly near the 3 and 9 o'clock positions (viewed in the direction of flow). Wrinkling and tenting were observed along most of the ruptured segment, most pronounced at the 3 o'clock position over the longitudinal seam. Wrinkling and tenting are forms of disbondment of the coating. (The loss of the bond [the adhesion] between a pipeline and its protective coating commonly is called disbondment, which has been known to allow moisture to become trapped between the surface of the pipe and the tape, creating an environment that may be corrosive.) The pattern and location of the wrinkles in the tape coating were consistent with soil loads acting on the pipe.⁴⁴ Corrosion was observed beneath the areas where the adhesive bond between the pipe and its protective tape coating had deteriorated. In the areas of disbondment, metal loss was found around and below the longitudinal seam in the upstream and downstream sections of pipe. Because the tape had become disbonded, the pipeline's cathodic protection⁴⁵ was prevented from reaching the pipe; it no longer prevented corrosion from occurring.

1.7.2 Corrosion

External corrosion was observed along the length of the pipe in areas where the coating had disbonded. The corrosion was generally shallow with interspersed deeper pits and did not show a morphology typically associated with microbial-induced corrosion. The deepest corrosion pit measured in the vicinity of the rupture, near the deepest crack penetration, was 0.078 inch. The internal surface of the pipe was free from any apparent corrosion or other visible surface anomalies.

1.7.3 Microbial Corrosion

The EPA and the NTSB conducted testing for activity of microorganisms typically found to cause corrosion in pipes. Microbial test results depend upon many factors, such as, when and where the samples were taken. During its testing, the EPA used liquid samples that were collected from the space between the pipe surface and the coating; whereas, the NTSB used samples that were collected several weeks after the accident from the pipe surface immediately after the coating was removed.

⁴⁴ Soil loads can act to either open or close tenting gaps, and soil loads can cause wrinkles to form after a pipe's installation. Soil loads on top of a pipe tend to close tenting gaps, whereas soil loads on a side of the pipe tend to open tenting gaps and wrinkles. Tenting gaps and wrinkles are most prevalent near the 3 o'clock and 9 o'clock positions of a pipe.

⁴⁵ *Cathodic protection* is a corrosion mitigation method used by the pipeline industry to protect underground steel structures. The system uses direct current power supplies at selected locations along the pipeline to supply protective electrical current. Cathodic protection current is forced to flow in the opposite direction of currents produced by corrosion cells. The protective current is supplied to the pipeline through a ground bed that typically contains a string of suitable anodes, with soil as an electrolyte. A wire connected to the pipeline provides the return path for the current to complete the circuit.

On August 6, 2010, after the ruptured pipe was exposed in the trench, the EPA conducted three microbial tests of the liquid samples extracted from the space between the longitudinal seam and the tape coating. A high concentration (that is, at least 100,000 cells/milliliter) of various microorganisms—including sulfate-reducing bacteria, acid-producing bacteria, and anaerobic bacteria—were found in two of the three samples.

On August 27, 2010, the NTSB conducted additional microbial tests at its materials laboratory. Corrosion products and deposit samples were taken from the external surface at the longitudinal seam and from another area away from the longitudinal seam. Low concentrations (that is, 1 to 10 cells/milliliter) of anaerobic and acid-producing bacteria were detected in the longitudinal seam sample, and a low concentration of anaerobic bacteria was found in a base metal sample. No sulfate-reducing bacteria were detected. In addition, features typically associated with microbial corrosion were not observed on the corroded areas of the pipe.

1.7.4 The Fracture

The fracture measured 6 feet 8.25 inches in length with the upstream end of the fracture located 24 feet 5.75 inches away from the upstream girth weld. The widest point along the fracture measured 5.32 inches and was about 4 feet from the upstream end of the rupture. The upper fracture face at the widest opening was measured at 1.38 inches below the longitudinal seam weld away from the heat-affected zone, with this offset ranging from 0.5 to 1.5 inches below the longitudinal weld seam for the length of the fracture face. (See figure 12.)

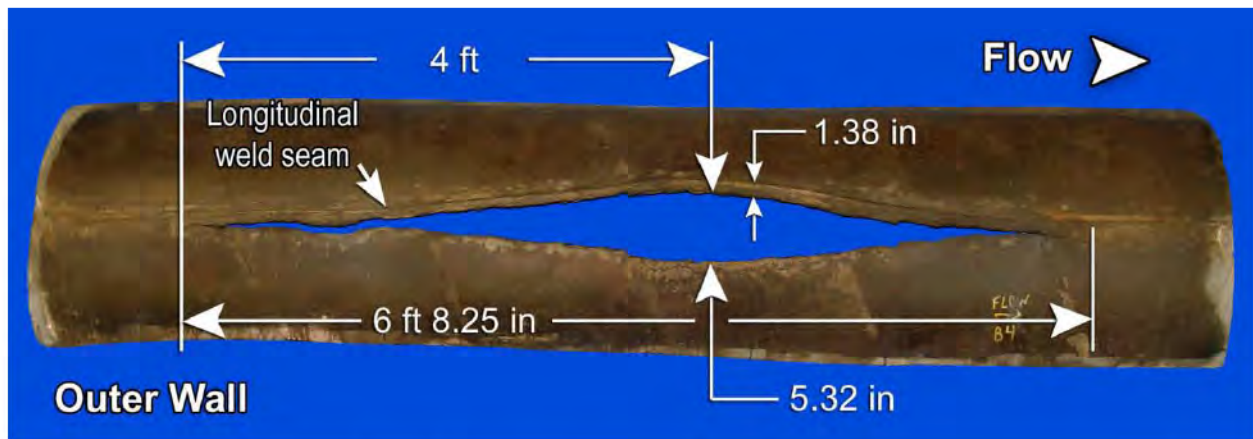


Figure 12. The outside surface of the pipe looking at the fracture area cut for lab examination.

Examination of the fracture face revealed features on slightly offset planes consistent with preexisting cracks initiating from multiple origins in corroded areas on the exterior surface. Evidence of preexisting cracks at various penetration depths was observed across nearly the entire length of the fracture surface. The area of deepest preexisting crack penetration, relative to the original local wall thickness, was located 50.25 inches from the upstream end of the rupture.

A continuous series of preexisting cracks was found extending from the outer edge of the fracture surface, linked together on the fracture surface, up to 10.8 inches upstream and 7.9 inches downstream from the area of deepest penetration. (See figure 13.) Black oxide was

observed on the preexisting crack portion of the fracture consistent with oxidation in an oxygen-poor environment.

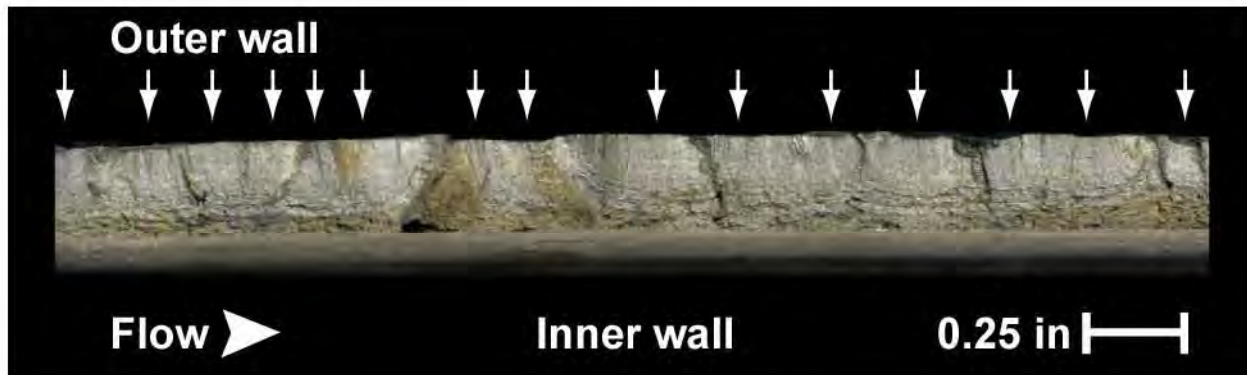


Figure 13. Curving arrest lines of preexisting cracks along the upper fracture face shown after cleaning to remove oxides. White arrows indicate multiple origin areas of preexisting cracks.

At the deepest crack penetration (see figure 14), the preexisting cracks extended 0.213 inch deep into the wall of the pipe relative to the original exterior surface, or 83.9 percent of the original wall thickness of 0.254 inch. The curving line in figure 14 indicates the extent of preexisting crack growth near the deepest penetration. The remainder of the fracture face had rough, matte gray features consistent with an overstress fracture. The preexisting cracks had fracture features perpendicular to the outside surface, consistent with corrosion fatigue^{46,47} or near-neutral pH stress corrosion cracking (SCC).⁴⁸ Fine crack arrest features were present within about 0.015 inch of the crack origins with broader crack arrest features appearing farther away from the origins. These crack arrest features were indications of progressive crack growth and can be associated with corrosion fatigue or near-neutral pH SCC.

⁴⁶ *Corrosion fatigue* is a mode of cracking in materials under the combined actions of cyclic loading and a corrosive environment. Corrosion fatigue crack growth rates can be substantially higher in the corrosive environment than fatigue crack growth under cyclic loading in a benign environment.

⁴⁷ (a) National Energy Board Report of the Inquiry MH-2-95, *Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines*, National Energy Board Canada (1996). (b) *Fractography*, Metals Handbook, Ninth Edition, Vol. 12, ASM International, 1987. (c) J.I. Dickson and J.P. Bailon, "The Fractography of Environmentally Assisted Cracking," in A.S. Krausz, ed., *Time Dependent Fracture: Proceedings of the Eleventh Canadian Fracture Conference, June 1984, Ottawa, Canada* (Dordrecht: M. Nijhoff Publishers, 1985).

⁴⁸ *Near-neutral pH SCC* is a form of cracking produced under the combined action of corrosion and tensile stress typically manifesting as clusters of small cracks in the external body of the pipe that can form long shallow flaws. Near-neutral pH SCC cracks propagate through the metal grain boundaries and with little secondary branching. It was first noted on a polyethylene-tape-coated pipeline in the TransCanada Pipelines system in the 1980s.

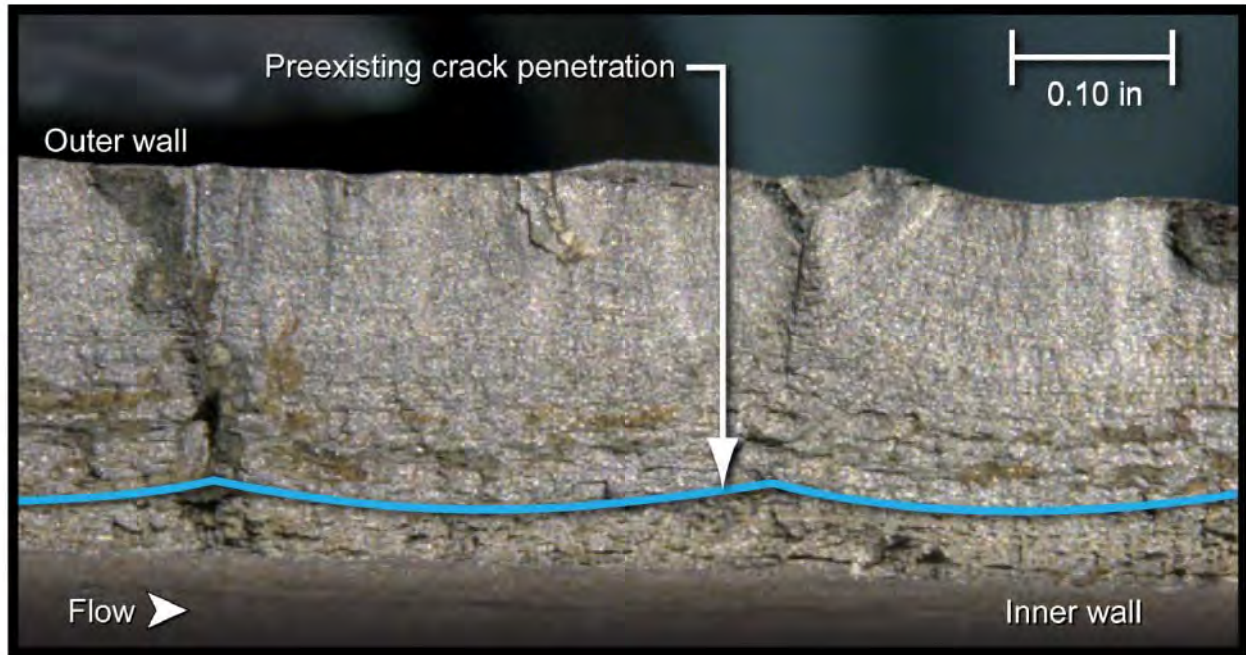


Figure 14. Close view of fracture surface area in the area of deepest crack penetration. The solid blue line indicates the extent of the preexisting crack penetration.

A cross-section through the fracture was prepared as shown in figure 15. The preexisting crack portion of the fracture showed a transgranular⁴⁹ fracture path with limited crack branching, consistent with near-neutral pH SCC or corrosion fatigue. Multiple closely spaced and parallel secondary cracks (with transgranular propagation paths and limited crack branching) emanated from corrosion pits on the outside wall near the fracture face, also consistent with corrosion fatigue or near-neutral pH SCC. The deepest secondary crack extended through about 43 percent of the wall thickness.

⁴⁹ A fracture that propagates through the metal grains rather than following the grain boundaries.

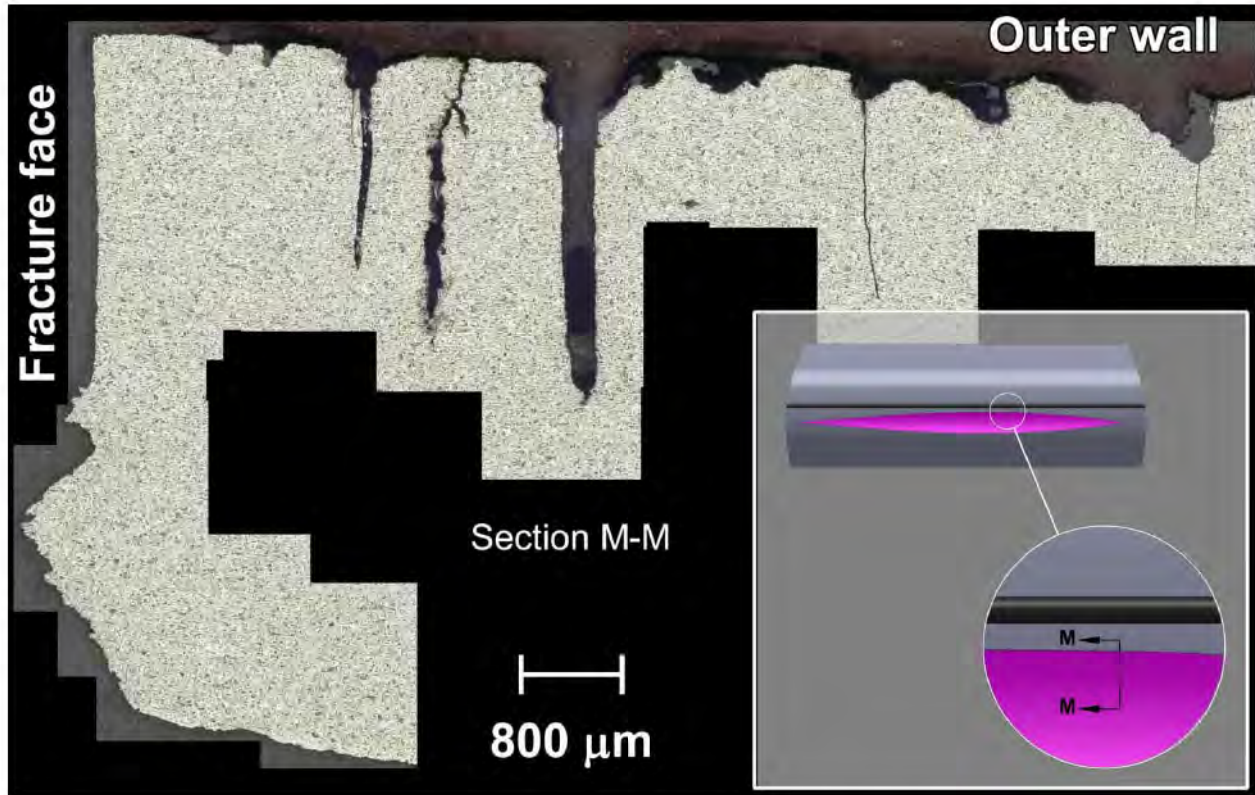


Figure 15. Transverse section through the top of the fracture showing multiple parallel cracks emanating from corrosion pits on the outside surface.

1.7.5 Crack and Corrosion Depth Profile

The preexisting crack depth and corrosion depth along the length of the rupture was measured relative to the original local wall thickness (as shown in figure 16).⁵⁰ The corrosion depths, which were measured on the fracture face under a microscope, did not necessarily reflect the deepest corrosion within the field of view but reflected the corrosion depth at the location where the crack depth was measured for each point. The corrosion depth at the location of deepest penetration measured in the plane of fracture was about 0.030 inch relative to the original wall thickness. The maximum depth of penetration of the preexisting cracks relative to the approximate original exterior wall surface was 0.213 inch at a location corresponding to approximately 28 feet 8 inches (344 inches) downstream of the upstream girth weld.

⁵⁰ Original wall thickness was measured adjacent to the fracture in areas appearing free of corrosion. The original outer wall location relative to the fracture was determined from the thickness measurement relative to the inner edge of the fracture face.

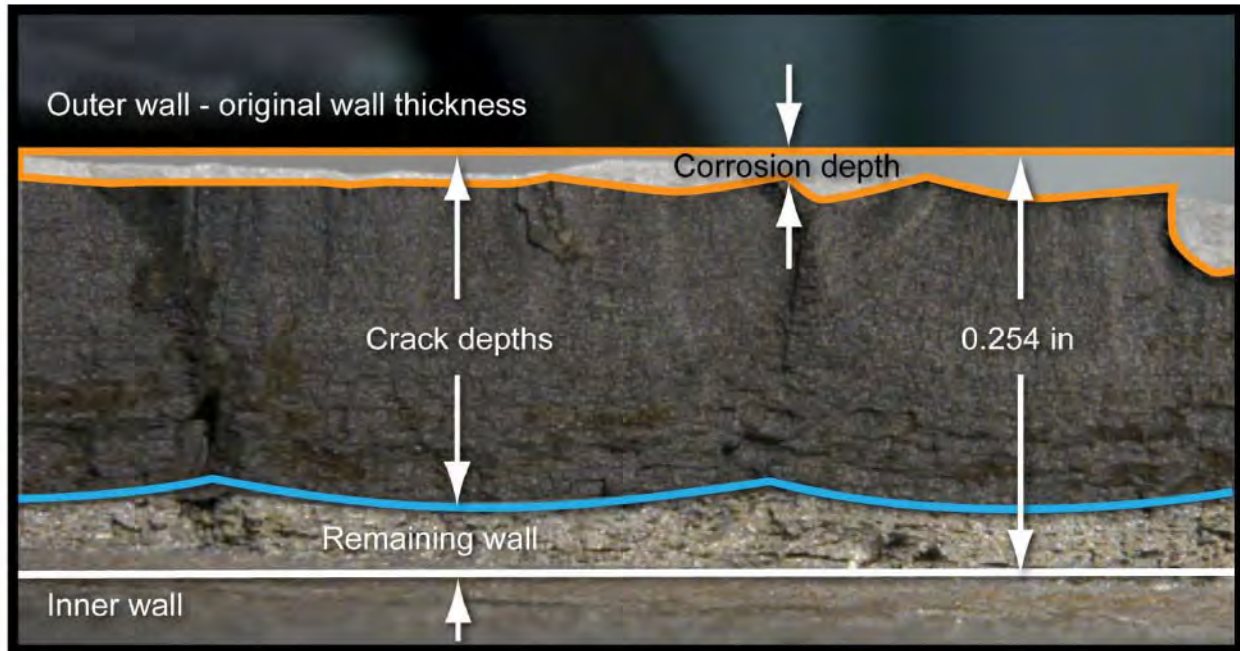


Figure 16. Lab measurements of crack and corrosion depths along the fracture face measured from images similar to figure 14 near area of deepest penetration (about 344 inches from upstream girth weld).

1.7.6 Mechanical Testing and Chemical Analysis

Tensile properties of all test specimens conformed to the requirements for yield strength, tensile strength, and elongation of grade X52 pipe as specified in the 1968 API Standard 5LX, *Specification for High-Test Line Pipe*. The chemical analysis for each sample tested conformed to the requirements for X52 pipe as specified in the 1968 API Standard 5LX, *Specification for High-Test Line Pipe*.

1.8 PHMSA Integrity Management Regulation

1.8.1 Pipeline Integrity Management in High Consequence Areas

On December 1, 2000, PHMSA amended 49 CFR Part 195 to require pipeline operating companies with 500 or more miles of hazardous liquid and carbon dioxide pipelines to conduct integrity management in HCAs.⁵¹ On January 16, 2002, PHMSA extended this regulation to include operators who owned or operated less than 500 miles of hazardous liquid and carbon dioxide pipelines.⁵²

⁵¹ *Federal Register*, vol. 65, no. 232 (December 1, 2000), p. 75378.

⁵² *Federal Register*, vol. 67, no. 11 (January 16, 2002), p. 2135.

Based on the comments PHMSA received in 2001, it amended the integrity management regulation, including the repair and mitigation provisions on January 14, 2002,⁵³ which became effective on May 29, 2001, except for paragraph (h) of 49 CFR 195.452, which became effective on February 13, 2002. According to PHMSA, the API had objected to the use of the word “repair” to describe the action required to address anomalies that could reduce a pipeline’s integrity. PHMSA agreed with the API that the word “repair” might be too narrow to cover the range of actions an operator could take to address a safety issue. PHMSA replaced the word “repair” with “remediate.” PHMSA also stated that although it firmly believes that repair is necessary to address many anomalies, it may not be necessary in all cases.

1.8.2 Elements of Integrity Management and Integration of Threats

As published, 49 CFR 195.452(e) lists risk factors (that is, pipe size, material, leak history, repair history, and coating type) that a pipeline operator must consider for establishing both baseline and continued pipeline assessment schedules. The elements of an integrity management program are listed in 49 CFR 195.452(f). Specifically, an operator must include, “an analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure” in its written integrity management program.

The director of PHMSA’s engineering and research division told investigators that “integration of all information about the integrity of the pipeline” in 49 CFR 195.452(f)(3) means that all threats are to be evaluated using an overlay or side-by-side analysis that would include cathodic protection, coating surveys, in-line inspection tool findings (for example, geometry, crack, and corrosion), and previous dig reports. He expected PHMSA inspectors to look for issues during an inspection to ensure that operators are implementing this methodology.

1.8.3 Discovery of Condition

Title 49 CFR 195.452(h) explains the actions an operator must take to address integrity issues for liquid pipelines in HCAs. Under the general requirements, “an operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis.” The regulation further states the following:

Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

⁵³ *Federal Register*, vol. 67, no. 9 (January 14, 2002), p. 1650.

1.8.4 Immediate and 180-Day Conditions

Title 49 CFR 195.452(h)(4)(i) requires immediate repair for several conditions, including those exhibiting “metal loss greater than 80 percent of [the] nominal wall regardless of dimensions” and those for which “a calculation of remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly.” The regulation identifies two acceptable methods of calculating the remaining strength of corroded pipe. Title 49 CFR 195.452(h)(4)(iii) addresses nine conditions that require remediation within 180 days. Four of these are listed below:

- (D) a calculation of the remaining strength of the pipe that shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, [American Society of Mechanical Engineers (ASME)]/[American National Standards Institute] B31G (“Manual for Determining the Remaining Strength of Corroded Pipelines” (1991)) or AGA Pipeline Research Committee Project PR-3-805 (“A Modified Criterion for evaluating the Remaining Strength of Corroded Pipe” (December 1989)).
- (G) A potential crack indication that when excavated is determined to be a crack.
- (H) Corrosion of or along a longitudinal seam weld.
- (I) A gouge or a groove greater than 12.5 percent of nominal wall.

On March 15, 2012, NTSB staff met with PHMSA representatives to discuss regulations covering hazardous liquid pipelines. During the meeting, the director of PHMSA’s engineering and research division stated that in accordance with 49 CFR 195.452 (h)(4)(iii)(G), PHMSA expects that all cracks will be excavated.

1.9 Enbridge Integrity Management Program

The Enbridge pipeline integrity department has been responsible for monitoring and implementing repair or remediation activities that are pertinent to mainline pipelines. The department is divided into three groups responsible for evaluating the risks associated with corrosion, cracks, and geometry-related issues. All of the groups rely on in-line inspection technologies to assess the integrity of the pipeline and identify potential threats. The crack and corrosion groups perform engineering assessments on the data received from the final in-line inspection reports to prioritize and schedule pipeline excavations. Excavations are conducted to evaluate the in-line inspection results, to remediate or repair defects, and to examine the condition of the pipeline segment.

1.9.1 Corrosion Management

Enbridge’s corrosion management group is responsible for both internal and external pipeline corrosion. SCC is evaluated under the crack management program.

Enbridge evaluated pipeline internal corrosion susceptibility by integrating and evaluating data on pipeline characteristics, in-line inspection data, operating conditions, pipeline cleanliness, crude and sludge sampling, and historical leak data. In 1996, Enbridge began a chemical inhibition program to prevent internal corrosion of Line 6B by using an inhibitor.

The corrosion management group monitors and inspects for external corrosion primarily through in-line inspections. The integrity analysis engineer is responsible for developing a list of features to be excavated (that is, the dig list) based on an analysis of the corrosion in-line inspection data. The corrosion group relies on two different tool inspection technologies (ultrasonic and magnetic flux leakage [MFL]) to locate and detect corrosion defects in the pipeline. The dig list developed from the inspection final report will include all features that meet the excavation criteria that have not been excavated, assessed, and repaired in the past. Enbridge’s corrosion excavation criterion is to excavate any feature that either exceeds 50 percent wall thickness loss or has a predicted failure pressure of less than 1.39 times the MOP. Enbridge had no clearly documented procedure that required the integrity analysis engineer to share corrosion in-line inspection data and excavation data with the people responsible to develop a dig list from crack or geometry tool in-line inspection data. According to Enbridge procedures, Enbridge would impose a pressure restriction for any feature requiring immediate repair. For a corrosion feature, the pressure restriction was based on ASME-sponsored code B31G, 2009 edition, *Manual for Determining the Remaining Strength of Corroded Pipelines: Supplement to ASME B31 Code for Pressure Piping*.⁵⁴ This is an approved method for calculating the remaining strength of the pipe for corrosion specified at 49 CFR 195.452.

1.9.2 Crack Management

To monitor its pipelines for cracks, Enbridge used in-line inspections, direct assessment (excavation and examination), and fitness-for-service⁵⁵ engineering assessment techniques.⁵⁶ Enbridge performed engineering assessments to manage crack defects identified through in-line inspections of its pipelines. Enbridge relied on a single ultrasonic crack inspection technology (the USCD tool) to perform crack inspections.

⁵⁴ The ASME-sponsored codes for pressure piping in this report are referred to as ASME codes, even though several other organizations have also been associated with their development over time. The ASME code for pressure piping was originally developed in cooperation with the American Engineering Standards committee, which later changed its name to the American Standards Association, and then to the American National Standards Institute, Inc.

⁵⁵ Fitness-for-purpose and fitness-for-service have been used interchangeably, representing engineering assessments used to calculate the adequacy of a structure for continued service under current conditions.

⁵⁶ The fitness-for-service techniques were consistent with the British Standard 7910, “Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures,” and API 579-1/ASME FFS-1 2007, *Fitness-for-Service*.

Enbridge's crack management group received a finalized in-line inspection report characterizing defects, which included crack-like or crack-field features. Enbridge interpreted crack-like as single linear cracks and crack-field indications as SCC colonies and applied separate criteria for excavation to each characterization. For crack-like features, the report included a maximum length and depth. For crack-field features, the report included the length of the colony, the longest crack indication (individual crack) in the colony, and a maximum depth. In 2005, Enbridge requested all crack depths be reported as a percentage of the tool-reported wall thickness. The crack depths were reported in ranges of less than 12.5 percent, 12.5 to 25 percent, 25 percent to 40 percent, and greater than 40 percent of wall thickness.

Enbridge excavation criteria for crack-like features was a predicted failure pressure from an engineering assessment less than the hydrostatic test pressure, which is defined as 1.25 times the MOP under 49 CFR 195.304. For crack-field features, Enbridge selected features that had a longest indication greater than 2.5 inches long or had a depth of 25 to 40 percent of the wall thickness. For a crack feature, the pressure restrictions were imposed based on a remaining strength calculation that showed a failure pressure less than the hydrostatic test pressure.⁵⁷ (The MOP was 624 psig for the ruptured segment.)

Enbridge provided the crack management excavation program summary worksheet from its 2005 crack tool in-line inspection showing over 15,000 defects on Line 6B. The worksheet listed 929 crack-like features identified by the in-line inspection tool; 29 of these features had a calculated failure pressure that was less than the hydrostatic test pressure (Enbridge crack excavation criteria). More than twice as many features (61 of the 929) had a calculated failure pressure that was less than 1.39 times the MOP (Enbridge's corrosion excavation criteria). All crack-field features 2.5 inches long or greater had been excavated.

1.9.3 In-line Inspection Intervals

Fatigue crack growth analysis was conducted by Enbridge on crack-like, crack-field, and notch-like features. Pressure cycle loading based on historical pressure data was used in the crack growth model, and a resulting fatigue life was determined. The time for the next scheduled in-line inspection for cracks was set to be no more than half the calculated fatigue life of any feature remaining in the line. Title 49 CFR 195.452(j)(3) requires that operators set 5-year intervals not to exceed 68 months for continually assessing the pipeline's integrity. Enbridge fatigue life calculations conducted using the 2005 in-line crack inspection data for Line 6B resulted in an estimated reinspection interval greater than the 5-year interval mandated under the regulation. Enbridge was performing the next in-line crack inspection of Line 6B in 2010 at the time of the accident.

⁵⁷ Under 49 CFR 195.304, this is stated as a minimum of 1.25 times the MOP.

1.9.4 Stress Corrosion Cracking

Enbridge's crack management plan focused on fatigue and SCC. The Enbridge SCC plan is part of its overall crack management program. About 39 percent of the Enbridge pipeline system is considered to have susceptibility to SCC based on the Canadian Energy Pipeline Association (CEPA) 1997 standard on SCC. About 35 percent of the total pipeline system has high susceptibility to SCC. The SCC management plan was developed about 1996 following the National Energy Board (NEB) public hearings on SCC in pipelines.

As a policy, Enbridge examined all excavated pipeline segments for SCC.⁵⁸ CEPA's recommended SCC mitigation approach included hydrostatic retesting, in-line inspection if appropriate tools were available, extensive pipe replacement, and recoating. CEPA considered hydrostatic retesting and in-line inspection to be temporary mitigation techniques. In contrast, repairs such as recoating the pipe, installing sleeves, grinding away the defects, and replacing the pipe were permanent mitigation techniques. According to CEPA, hydrostatic retesting has been shown to be an effective means for identifying near-critical axial defects, such as SCC.

1.9.5 Coating and Cathodic Protection

Line 6B was coated with field-applied Polyken number 960 polyethylene tape coating. Enbridge operates over 1,100 miles of polyethylene-tape-coated pipelines in the United States, which represents about 25 percent of its U.S.-based transmission mileage. Tape-coated portions of Line 6A (410 miles) and Line 6B (283 miles) represent the two longest pipelines making up the 25 percent. Enbridge Lines 6A and 6B were both installed in the late 1960s. The coating on Line 6B was composed of a 9-mil-thick⁵⁹ polyethylene backing and a 4-mil-thick synthetic rubber (synthetic resin) adhesive. According to Enbridge, this type of external tape coating and its typical degradation mode are key factors in determining the pipeline's potential susceptibility to SCC. This susceptibility to SCC was due to the higher tendency of this tape coating to lose adhesion (disbondment), exposing the pipe to a potentially corrosive environment while preventing cathodic protection from reaching the pipe.

In addition to the polyethylene tape wrap on Line 6B, Enbridge operated a cathodic protection system to protect the line from corrosion. Pipe-to-soil electrical potential readings taken on July 31, 2010, showed operating levels were above the minimum acceptable criteria established under 49 CFR 195.571. Even with cathodic protection levels operating in excess of the minimum levels specified in the regulations, disbonded tape coating can shield the cathodic protection current from reaching the exposed pipe wall, allowing corrosion to form on the external pipe surface.

⁵⁸ An SCC colony is assessed to be "significant" if the deepest crack, in a series of interacting cracks, is greater than 10 percent of wall thickness, and the total interacting length of the cracks is equal to or greater than 75 percent of the critical crack length of a 50-percent through wall crack at a stress level of 110 percent of SMYS.

⁵⁹ One mil equals 1/1,000 inch.

1.9.6 In-line Inspection Tools

A variety of in-line inspection tool technologies are used to estimate the size and location of defects that may be on the inside or outside surfaces of the pipe wall. Different tools and technologies are employed by operators depending on the type, orientation, and location of the defects. Since 2004, Enbridge had inspected Line 6B using three types of tools: UltraScan Wall Measurement (USWM), USCD, and MFL.

The USWM tool, which is an Elastic Wave tool, works by sending ultrasound in two directions through the pipe wall and is useful for detecting wall thickness lost to corrosion. The USCD tool detects longitudinal defects (cracks) in a pipe wall using the reflected ultrasonic signals from the defects in the pipe wall to locate and size cracks. The transverse MFL tool relies on magnetic fields to detect defects (cracks and corrosion) in the pipe wall and longitudinal seams.

Despite their sophistication, the detection capabilities of in-line inspection tools have limitations. Each tool technology has a stated minimum defect size that can be detected and the tool can be subjected to interference from nearby anomalies or geometry. The ability of the tool to detect a feature of minimum size is known as the probability of detection. Probability of indication represents the uncertainty involved in the post-processing and interpretation of the raw signals. Once detected, tool data are analyzed through sizing and selection algorithms and, finally, by a data analyst, who characterizes the feature by type.

Enbridge told NTSB investigators that, when the right technology and processes are implemented, in-line inspection has been shown to be more effective than hydrostatic testing at maintaining a reliable pipeline. At the time of the accident, Enbridge had not performed hydrostatic pressure testing on Line 6B since the time of its construction. Enbridge stated it preferred to assess line integrity using in-line inspection tools.

1.9.6.1 USCD Tool

The USCD tool was designed to detect, locate, and size axially aligned cracks in liquid pipelines; it requires a liquid coupling between the ultrasonic sensors and the inner pipe wall to allow sound waves to pass between the tool and the pipeline. The amplitude of the sound returning at 45° allows estimation of the depth of a crack or cracks in the pipeline. A crack must be more than 1.18 inches long and 0.0393 inch deep to be detected by the tool and characterized by the in-line inspection analyst. The tool reports single (crack-like) and multiple cracks (crack fields) that are axially aligned, in both the body of the pipe and the seam weld area. To account for uncertainty in the depth sizing, the USCD tool has a tolerance of ± 0.02 inch for reported feature depths. However, Enbridge did not account for a tool tolerance in its analysis of the crack depths in the 2005 USCD analysis.

In 2005, Enbridge requested that the crack depth be reported in depth ranges expressed as a percentage of the tool-reported wall thickness. Crack depths are reported in ranges to account for error in the tool's ability to estimate depth. The tool-reported depth ranges were as follows: 0–12.5 percent, 12.5–25 percent, 25–40 percent, and greater than 40 percent.

The USCD tool reported a wall thickness value for each segment of pipe. According to PII, the wall thickness was measured by the tool to facilitate feature sizing; the measurement was not intended to be an accurate representation of the local wall thickness of the segment.

PII stated that for cracks above the detection threshold and located in shallow corroded areas, the detection and identification would be distinctive and based on the reflected echo; however, the reported depth would relate only to the crack indication, not to the depth of the corrosion. (Therefore, it is important to note that the corrosion depth must be added to the crack estimated depth to establish the true extent of the crack depth.) An exception to this occurs when a crack is located at the edge of steep-sided corrosion. In this case, corrosion depth will not affect the depth sizing and the tool will report the actual crack depth. PII further stated that the information regarding the impacts of corrosion on crack sizing was not mentioned in its brochures and had not explicitly been given to Enbridge. The following impacts on performance may occur when an in-line inspection tool is detecting a crack in shallow corrosion:⁶⁰

- [Probability of detection] – Signals reflected by corrosion could be diffused and overlaid on the signals of shallow cracks.
- [Probability of indication] – Weak signals could be identified as rough surface and therefore not sized and reported.
- Depth Estimation – The sizing performance could be affected by diffused and overlaid signals of the corrosion.

Enbridge’s director of the integrity management program told NTSB investigators that an operator should consider the corrosion and crack features identified by in-line inspection tools; however, Enbridge prefers to monitor tool accuracy by comparing the in-line inspection tool reported depths with the actual depths measured at the time of excavation. The Enbridge 2005 and 2006 field excavation evaluation procedures stated that defect depth should include crack depth plus wall loss, but in 2005 no similar process was in place under the integrity crack management program to incorporate the findings from field evaluations of the tool-reported crack depth into the engineering assessments.

1.9.7 Enbridge Postaccident Threat Assessment Review

Dynamic Risk Assessment Systems, Inc., a contractor, conducted a systemwide threat assessment review for Enbridge in 2011. Based on Enbridge’s 1984–2010 leak report database, the review concluded that external corrosion had caused 14 percent of the past failures. Environmentally assisted cracking⁶¹ was responsible for 3 percent of the failures. The review report stated, “External metal loss is one of the morphological traits associated with near-neutral pH SCC and corrosion fatigue.” The report further stated, “the environmentally assisted cracking mechanism that is most prevalent along Enbridge’s liquid pipeline system is either near-neutral

⁶⁰ See the item titled “IMP [Integrity Management Program] PII Documents” in the NTSB public docket for this accident.

⁶¹ An environmentally assisted crack is corrosion fatigue or stress corrosion cracking that is accelerated by a corrosive environment.

pH SCC or corrosion fatigue.” For Line 6B, the review report categorized manufacturing defects and external corrosion as significant threats and SCC as a moderate threat.

1.9.8 Prior In-Line Inspections of Line 6B

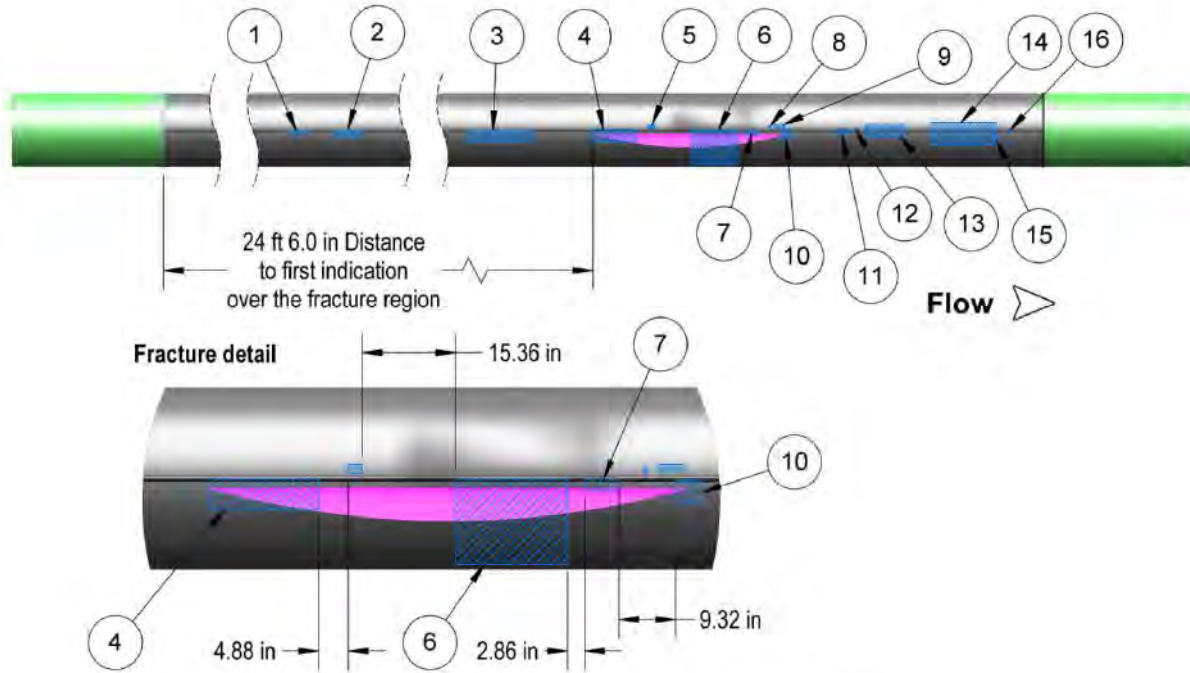
In-line corrosion inspections were performed in 2004, 2007, and 2009 using both MFL and ultrasonic in-line inspection tools. The first in-line crack inspection performed on Line 6B, following the introduction of the integrity management rule, was in 2005 using the USCD tool. The following are summary findings from those inspection reports.

1.9.8.1 2004 Ultrasonic Wall Measurement In-Line Inspection

In 2004, Enbridge contracted PII to conduct an in-line corrosion inspection on Line 6B using an USWM tool. The PII inspection report for this inspection listed 50,270 corrosion features on Line 6B, with 1,037 of those features having predicted failure pressures of less than 1.39 times the MOP or SMYS. Sixteen external corrosion features identified from the inspection were located on the ruptured segment; 12 of these were on the longitudinal seam weld, and 4 were near the seam weld. Four regions of external corrosion were identified within the immediate rupture location (see figure 17); however, none of these features met the Enbridge criteria for excavation (predicted failure pressure that was less than 1.39 times the MOP). At the location within the fracture corresponding to the deepest preexisting crack penetration⁶² identified by the NTSB Materials Laboratory, the 2004 USWM inspection report documented an area of corrosion measuring 18.5 inches long located about 0.80 inch below the longitudinal seam weld with a maximum recorded depth of 0.087 inch (34 percent of the wall thickness). This area of corrosion was located 27.92 feet from the upstream girth weld. In June 2004, Enbridge imposed a pressure restriction at the Marshall PS based on corrosion findings (downstream of the Marshall PS near MP 611) from the 2004 in-line inspection that limited the discharge pressure to 525 psig. The 2004 inspection results included some corrosion indications with estimated depths that might have been undersized due to echo loss.⁶³ To supplement the readings affected by the echo loss, Enbridge performed a second corrosion inspection in 2007.

⁶² Located 28 feet 8 inches from the upstream girth weld.

⁶³ Echo loss occurs when the sound signal is not reflected back to the transducer of the inspection tool, resulting in missing or lost data. PII stated that it used an algorithm to determine the depth of features in cases where echo loss occurred.



2004 USWM corrosion features on the ruptured segment

| Feature ID | Distance from upstream girth weld (ft) | Width of area (degrees) | Local wall thickness (in) | Length of area (in) | Deepest indication (in) |
|------------|--|-------------------------|---------------------------|---------------------|-------------------------|
| 1 | 10.22 | 101 - 107 | 0.268 | 7 | 0.047 |
| 2 | 11.73 | 101 - 109 | 0.26 | 11.6 | 0.047 |
| 3 | 20.24 | 101 - 118 | 0.26 | 25.9 | 0.055 |
| 4 | 24.5 | 101 - 120 | 0.252 | 18.4 | 0.055 |
| 5 | 26.44 | 91 - 97 | 0.26 | 2.4 | 0.047 |
| 6 | 27.92 | 100 - 153 | 0.252 | 18.5 | 0.087 |
| 7 | 29.7 | 101 - 108 | 0.252 | 5.8 | 0.047 |
| 8 | 30.52 | 93 - 96 | 0.252 | 0.6 | 0.047 |
| 9 | 30.72 | 91 - 96 | 0.252 | 4.1 | 0.047 |
| 10 | 30.96 | 101 - 116 | 0.252 | 4.3 | 0.047 |
| 11 | 32.87 | 101 - 109 | 0.252 | 4.7 | 0.055 |
| 12 | 33.41 | 101 - 104 | 0.252 | 1.6 | 0.047 |
| 13 | 33.82 | 91 - 109 | 0.252 | 16.5 | 0.055 |
| 14 | 36.02 | 88 - 123 | 0.252 | 27.4 | 0.063 |
| 15 | 38.24 | 109 - 115 | 0.26 | 1.2 | 0.047 |
| 16 | 38.7 | 100 - 104 | 0.26 | 1 | 0.055 |

The longitudinal seam weld was reported by the tool as oriented 100 degrees clockwise from the top of the pipe

Figure 17. 2004 corrosion inspection of Line 6B and 16 regions of corrosion identified by the tool on the ruptured pipe segment. The detail view shows the areas of corrosion overlapped with the rupture location.

1.9.8.2 2005 In-Line Inspection—PII USCD Crack Tool Results

The 2005 USCD tool report identified 7,257 crack-like, crack-field, and notch-like features on Line 6B. The report included six indications of crack-like features located on the external surface that were adjacent to the weld in the ruptured segment. All of the features in the ruptured segment were oriented between 98° to 102° relative to the top of the pipe and were located below the longitudinal weld seam, which the inspection report stated was at 96° relative to the top of the pipe.

Wall thickness of the ruptured segment was measured by the 2005 USCD in-line inspection tool and reported as 0.285 inch for the entire segment length. This tool reported wall thickness was used by PII when reporting the depths of all crack features as a percentage of wall thickness. PII stated that the wall thickness measured by the tool is not intended to be a local indication of wall thickness in the pipe segment. The tool-reported wall thickness value and crack depths⁶⁴ (reported as a percentage of tool-reported wall thickness) were used by Enbridge when conducting the engineering assessments of predicted failure pressure and fatigue life of the cracks. The assessments were the basis of selection for pipeline excavation and reinspection intervals.

PII identified six crack-like indications in the 2005 Line 6B in-line inspection report for the ruptured pipe segment. (See figure 18.) Two of the crack defects had depths of 12 to 25 percent of the tool-reported wall thickness. These features were 25.5 inches and 51.6 inches long and were located directly over the area of rupture. The deepest (with a depth of 25 to 40 percent of the tool-reported wall thickness) of the six crack-like features was 9.3 inches long and was located 11.04 feet from the upstream girth weld of the ruptured segment.

⁶⁴ The Enbridge procedure required that the maximum depth range be used for an initial engineering assessment; however, if the result of the initial calculation was less than the hydrostatic test pressure, a second assessment was performed using a refined crack depth (profile) requested from the in-line inspection vendor. PII stated that it does not stand behind the accuracy of refined depths or profiles. A profiled depth for the 9.3-inch crack-like feature was requested during the analysis of the 2005 in-line inspection data that resulted in the crack not being excavated.

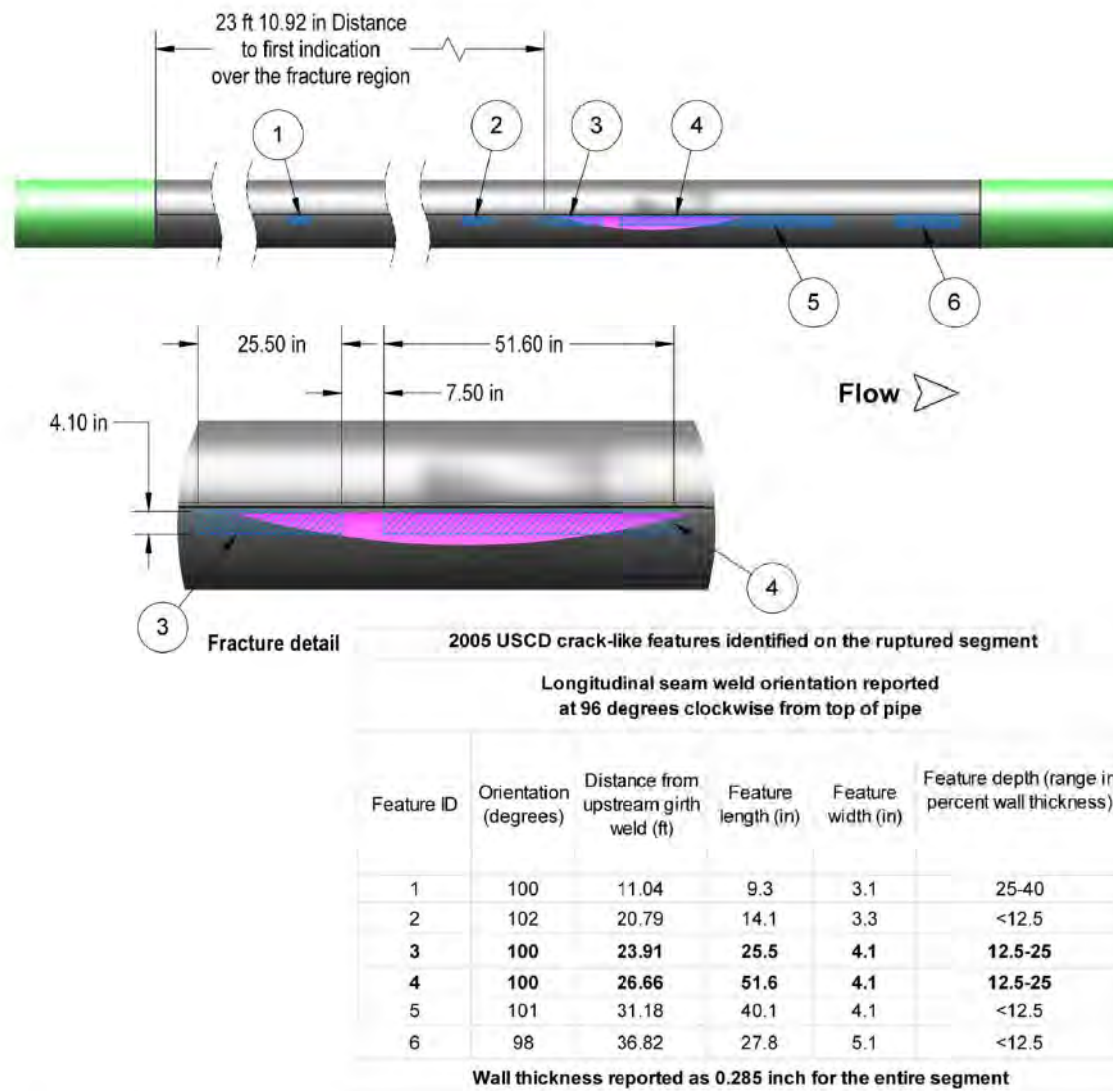


Figure 18. 2005 in-line inspection regions where crack-like characterizations were reported by PII on the ruptured segment of Line 6B.

According to PII, all six features identified on the ruptured segment, including the 51.6-inch-long crack, were originally characterized as crack-field indications by a junior analyst; however, a supervisor changed the analyst’s characterizations to crack-like defects during a final quality check.

The Enbridge excavation criteria for crack fields required that features with a longest indication of 2.5 inches or larger or with a depth of 25 to 40 percent of the wall thickness be scheduled for excavation. Features reported as crack-like were selected for excavation if the depth was greater than 40 percent of the wall thickness or an engineering assessment resulted in a predicted failure pressure that was less than the hydrostatic pressure of the pipeline.

Using fitness-for-service software, Enbridge conducted engineering assessments for predicted failure pressures on all six of the reported crack-like defects. Enbridge used the

reported wall thickness and crack depths as they appeared on the final 2005 inspection report from PII or as profiled for the 9.3-inch-long feature. Each of these defects had a calculated failure pressure greater than the hydrostatic test pressure of the pipeline (796 psig). Further, none of those indications had a reported depth of greater than 40 percent of the tool-reported wall thickness. Based on the results of the engineering assessment, Enbridge did not identify any of the six crack-like defects on the ruptured pipeline segment for excavation and examination.

After the Marshall accident, PII reanalyzed the raw signal data from all of the six indications and stated that each should have been classified as crack-field features. A PII analysis of the 51.6-inch-long crack-like defect detected during the 2005 USCD in-line inspection showed that this defect should have been reported as a crack-field feature with a longest individual crack length of 3.5 inches. Also, using newer PII depth estimating algorithms, developed in 2008 for crack-field features, the depth of the 51.6-inch-long crack-field feature was characterized as 0.091-inch deep (32 percent of the tool-reported wall thickness). By comparison, the depth algorithm used in 2005 for the same 51.6-inch-long feature (crack-like feature depth analysis) showed a depth of 0.063 inch (22 percent of the reported wall thickness).

Following the accident, in 2011, Enbridge completed a crack inspection of Line 6B. The 2011 ultrasonic crack tool report identified 4,478 crack-like, crack-field, and notch-like features, which was a decrease from the 2005 inspection. (PII had made changes to its feature identification process in 2008.)

1.9.8.3 2007 In-Line Inspection—PII High-Resolution MFL Tool Results

Enbridge contracted PII to conduct a 2007 MFL inspection of Line 6B to confirm the depth estimates in areas of echo-loss identified during the 2004 USWM inspection. The 2007 MFL report included 67 corrosion features identified on the ruptured segment starting at about 4 feet and extending to 39.64 feet from the upstream girth weld. The inspection report for the 2007 MFL in-line inspection included a calculation of the predicted failure pressure for each defect on the pipe segment. Neither the deepest feature reported nor the feature with the lowest predicted failure pressure was located at the rupture location.

1.9.8.4 2009 In-Line Inspection—PII USWM Tool Results

In June 2009, PII conducted an in-line corrosion inspection of Line 6B using an USWM tool. The report issued to Enbridge in December 2009, which was revised by PII and reissued in June 2010, identified 273,759 metal loss features, and 6,791 of those features had predicted failure pressures that were less than 1.39 times the MOP and met the Enbridge excavation criteria. Nineteen features were found in the ruptured segment; however, none of them met the excavation criteria. All but four of the reported features in the ruptured segment were listed as external corrosion located near the seam weld, oriented between 87° and 99°. ⁶⁵ The feature with the lowest calculated predicted failure pressure in the ruptured segment was 28.2 feet from the upstream girth weld and measured 68.03 inches long by 17.05 inches wide.

⁶⁵ These positions are located clockwise from the 12 o'clock position or the top of the pipe (0°).

1.10 Pipeline Public Awareness Programs

1.10.1 Regulatory Requirements

Pipeline operators are required to develop and implement a written continuing public education program in accordance with 49 CFR 195.440. The regulation states that the program must provide awareness information to the public, appropriate local government officials, and emergency responders. The awareness information must include information about the possible hazards associated with releases, use of a one-call notification system, physical indications that a release has occurred, steps that should be taken in the event of a release, and procedures for reporting such a release.

1.10.2 API Recommended Practice 1162

Public awareness programs (PAP) must follow the guidance in API's Recommended Practice (RP) 1162, *Public Awareness Programs for Pipeline Operators* (December 2003). RP 1162 was incorporated by reference into the pipeline regulations (49 CFR 195.3(c)).

RP 1162 establishes guidelines for pipeline operators to develop, manage, and evaluate PAPs. RP 1162 identifies audiences that should receive awareness messages, the content of baseline awareness messages, and the frequency of the messages for each audience. Audiences defined in the standard include the affected public, emergency officials (including fire departments and police departments), and local public officials. RP 1162 states that the evaluation should include both the process and the program effectiveness. RP 1162 states that operators should evaluate the process annually and evaluate program effectiveness at intervals not greater than every 4 years. This evaluation should determine if the awareness messages are reaching the audiences and if the audiences understand the messages.

1.10.3 Enbridge's PAP

Enbridge's PAP was completed in June 2006 and revised in 2010. According to Enbridge, direct mail brochures were mailed to all audiences annually. Prior to the Marshall accident, the most recent direct mailings were in May 2010. For Calhoun County, 2,304 mailing addresses were listed. For Marshall, 509 mailing addresses were listed.

On February 28, 2010, Enbridge, along with six other pipeline companies, hosted safety awareness training in Jackson, Michigan, for emergency officials. Topics included product hazards and characteristics and leak recognition and response. One attendee was from the Marshall City Fire Department, and two attendees were from the Marshall Township Fire Department. Enbridge mailed its *2010 Michigan Pipeline Emergency Response Planning Information* manual to emergency response organizations that were not present for the safety awareness training.

Enbridge's program plan was reviewed informally by Enbridge's program awareness manager and formally through the Public Awareness Program Effectiveness Research Survey

(PAPERS) program.⁶⁶ The program was conducted every 2 years, and the most recent program was conducted in 2009 (prior to the accident). According to the PAPERS report, the objective of the survey was to determine if the public awareness information is reaching the intended stakeholder audiences and if the audiences understand the messages delivered. Twenty-six operators participated in the survey. For Enbridge’s survey, the report notes that there were 314 respondents from the affected public audience and 267 additional attendees from other audiences.⁶⁷ Tables 1 and 2 show the responses (in percentages) to two key questions about pipeline awareness and pipeline information.

Table 1. Awareness of pipelines in the community.

| Question: How well informed would you say you are regarding pipelines in your community? | | | |
|--|-----------------|------------------|---------------------|
| Response | Affected Public | Public Officials | Emergency Officials |
| Very well informed | 23% | 39% | 47% |
| Somewhat informed | 36% | 32% | 38% |
| Not too informed | 27% | 21% | 16% |
| Not at all informed | 15% | 8% | 0% |
| Don't know/refused | 0% | 0% | 0% |

Table 2. Pipeline information received.

| Question: Within the past two years (Affected Public)/12 months (Excavators, Emergency Officials)/three years (Public Officials), do you recall receiving any information from a pipeline company, or companies, relating to pipelines? | | | |
|---|-----------------|------------------|---------------------|
| Response | Affected Public | Public Officials | Emergency Officials |
| Yes | 55% | 64% | 77% |
| No | 45% | 34% | 21% |
| Don't know/refused | 0% | 2% | 2% |

⁶⁶ The PAPERS review is sponsored by the API, the Association of Oil Pipelines, and the Interstate Natural Gas Association of America. The PAPERS program is an industrywide survey conducted to assess the effectiveness of PAPS.

⁶⁷ This includes excavators, emergency officials, and public officials.

1.11 Enbridge Operations

1.11.1 Edmonton Control Center

The Enbridge pipeline system is controlled from a single SCADA control center located in Edmonton, Alberta, Canada. According to Enbridge's HCA management plan, dated March 2010, the Edmonton control center is the hub of emergency response and shuts down a pipeline within 8 minutes⁶⁸ of an abnormal condition when the condition cannot be identified or corrected. During a shutdown, control center staff contact operational personnel in the area to respond.

At the time of the accident, the control center was staffed by 22 control center operators, 2 shift leads, and an MBS analyst, all of whom worked in 12-hour shifts. Control center operators were grouped in pairs in what Enbridge referred to as "pods." Each console within a pod controlled two or more pipelines. A control center supervisor and the MBS analyst were either available at the control center or were on call on nights and weekends.

At the time of the accident, the MBS analyst reported to the information technology department. The MBS analyst position had been added to the control center in July 2008. Before the position existed, MBS alarms were handled by an on-call engineer; alarms were not analyzed in the control center. Operator A2 stated that over the last few years, the MBS analyst's role had evolved from determining whether the MBS program was working and an MBS alarm was valid to determining whether the operator should shut down the pipeline.

The control center was staffed by four groups of individuals involved in pipeline operational decisions. The control center operator was responsible for direct control of the movement of products through the pipeline. The control center operator was to start or stop pipeline flow according to a schedule determined by another Enbridge department, and in accordance with pipeline operating restrictions. The control center procedures gave authority to the control center operator to shut down the pipeline under specific circumstances or for any other reason that the control center operator determined to be in the best interests of safety.

Shift leads served as liaisons between operators and others involved in pipeline operations to facilitate pipeline operations. Their role was tailored toward managing the control center operators and assisting them in troubleshooting rather than solving pipeline operational issues. In this capacity, the shift leads were required to have had some technical experience in operations (typically that of an operator); however, a shift lead was not required to demonstrate a technical proficiency in pipeline operations on a regular basis. Operator B1 told investigators, "We don't have anybody that's designated as a technical person. They (shift leads) are people-people—people persons...they both have more experience than I do. So I would—I'm going to assume that they would know as much or more than I do." Shift lead B2 described his role as follows: "... I'm there to first and foremost be a people leader to the operators in the room and then also provide support where needed, whether that's technical support, whether

⁶⁸ Enbridge used an 8-minute timeframe for recognition and for shutting valves when calculating worst-case discharges on the pipeline. This time was different from the control center's 10-minute restriction, which required the control center operator to stop a pipeline under specific circumstances.

that's, I guess support as a leader with personal issues or anything that is involved in the control center.”

The on-call supervisor was above the shift lead in authority. His or her direct position within the Enbridge organizational structure varied according to the title of the person serving as on-call supervisor at that time. In general, the on-call supervisor, a position that varied according to a predetermined rotation schedule, was at the first or second level above the shift lead. His or her role was to confer with the shift lead and others in the control center when a pipeline operating issue could not be settled at the shift lead/operator level and approve or disapprove of a decision regarding pipeline operations. The MBS analyst, while not in the chain of command of the control center operator, shift lead, or on-call supervisor, provided expertise in response to MBS alarms. The role of the MBS analyst was to determine, according to his or her analysis of the data provided by the MBS software, whether the MBS software was operating correctly; however, the control center procedures set the expectation that the MBS analyst would tell the shift leads and control center operators whether a leak alarm was “valid” or “false”.

According to Enbridge’s vice president of customer service, who oversaw the control center and the pipeline scheduling department at the time of the accident, the company’s emphasis on shift leads’ leadership skills was based on an increase in the number of control center staff. On January 1, 2007, Enbridge employed 89 control center operators and 15 control center support staff. On July 15, 2010, these staff numbers rose to 117 and 37, respectively. The addition of new pipelines to the Enbridge system had necessitated increasing the control center staff. Some operators told NTSB investigators that the experience level in the control center had decreased as staff numbers increased.

1.11.2 Control Center Personnel Experience

NTSB investigators examined Enbridge control center documents to assess the experience levels of the control center staff who were on duty at the time of the accident. The shift leads had held their positions from 3 to 6 years and had obtained varying levels of experience before becoming shift leads. The control center operators working on shifts A, B, and C had from 3 to 30 years experience. Because the MBS analyst position was new to the control center as of 2008, the two MBS analysts had been in their positions 1.5 to 2 years. MBS analyst A had no prior pipeline operations experience. MBS analyst B had more than 20 years of experience as a control center operator before becoming an analyst. Table 3 lists the people involved in the Line 6B shutdown and startups on July 25 and 26, as well as their experience and position in the control center.

Table 3. Key control center staff involved in the accident and their years of experience.

| Shift A: Sunday 8:00 a.m.–Sunday 8:00 p.m. | | |
|--|---|---|
| Shift lead A1 | Pipeline/Terminal Consoles | 6 years as operator 3 years as shift lead |
| Shift lead A2 | Pipeline/Terminal Consoles | 25 years with Enbridge 6 years as shift lead |
| Operator A1 | Lines 3, 17, 6A, and 6B operator | 29 years as operator Requalifying on Line 6B after 6-month absence |
| Operator A2 | Mentor to operator A1 | 30 years experience |
| MBS analyst A | Responsible for MBS (leak detection) | Level II MBS analyst 1.5 years experience |
| Shift B: Sunday 8:00 p.m.–Monday 8:00 a.m. | | |
| Shift lead B1 | Pipeline/Terminal Consoles | 11 years with Enbridge 3 years as shift lead |
| Shift lead B2 | Pipeline/Terminal Consoles | 8 years with Enbridge 2.5 years as shift lead |
| Operator B1 | Lines 3, 17, 6A, and 6B operator | 3.5 years as operator |
| Operator B2 | Lines 4 and 14 operator and shiftmate to operator B1 | Just over 2 years as operator |
| MBS analyst B | Responsible for MBS (leak detection) | 20 years as operator 2 years as Level III MBS analyst |
| Control center supervisor (on-call) | On-call designated supervisor | 20 years operations experience 1.5 years as supervisor |
| Shift C: Monday 8:00 a.m.–Monday 8:00 p.m. | | |
| Shift lead C1 | Pipeline/Terminal Consoles | 15 years with Enbridge 5 years as shift lead |
| Shift lead C2 | Pipeline/Terminal Consoles | 8 years with Enbridge 2 years as shift lead |
| Operator C1 | Lines 3, 17, 6A, and 6B operator | 6 years as operator |
| MBS analyst A | See Shift A information | |

1.11.3 Toxicology

After the accident, as required by 49 CFR 199.105(b)⁶⁹ and 199.221,⁷⁰ Enbridge conducted drug⁷¹ and alcohol tests for each shift lead and Line 6B operator on duty during shifts A, B, and C. Specimens were collected from all the shift leads and operators A2 and C1 between 8:50 and 10:50 p.m. on July 27. Specimens were collected from operators A1 and B1 between 12:00 and 12:40 p.m. on July 28. The results of the drug tests were negative. However, these results were not valid because the alcohol testing was not conducted within the maximum time allotted after the rupture as specified in the regulations.

Enbridge did not explain to PHMSA why alcohol testing was not carried out within 8 hours of discovery of the rupture, as required by 49 CFR 199.221 and 199.225(a). Still, Enbridge tested these individuals even though more than 8 hours had passed since they had been on duty. The control center supervisor told investigators that the delay in testing was due to the delay in confirming the rupture and the fact that many of the personnel who had been on duty during the accident sequence had gone home by the time the rupture was identified.

1.11.4 Training and Qualifications

1.11.4.1 Control Center Operations

Enbridge's supervisor of training and compliance for control center operations was responsible for control center training. He also oversaw the operator qualification process required in 49 CFR 195.505. During postaccident interviews, he stated the following regarding operator training: "...the goal is for the operator to operate independently, but also with the support of the team members."

Operator training was conducted in five phases and typically lasted about 6 months. The initial phase of instruction consisted of classroom and web-based instruction covering material such as hydraulics, vapor pressure, viscosity, and specific gravity. The remaining phases incorporated on-the-job training with a mentor, problem solving, and abnormal operation recognition presented through a simulator. By the completion of the fifth phase, students were expected to recognize and respond appropriately to abnormal operating conditions, including column separation and leak scenarios. Upon successfully completing additional classroom

⁶⁹ The regulation states, "(b) Post-accident testing. As soon as possible but no later than 32 hours after an accident, an operator shall drug test each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this paragraph but such a decision must be based on the best information available immediately after the accident that the employee's performance could not have contributed to the accident or that, because of the time between that performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use."

⁷⁰ "Each operator shall prohibit a covered employee who has actual knowledge of an accident in which his or her performance of covered functions has not been discounted by the operator as a contributing factor to the accident from using alcohol for eight hours following the accident, unless he or she has been given a post-accident test under §199.225(a), or the operator has determined that the employee's performance could not have contributed to the accident."

⁷¹ The drug test included five classes of illegal drugs: marijuana, cocaine, opiates, amphetamines, and phencyclidine.

training, passing a written and oral examination administered by a trained evaluator, and demonstrating proficiency by operating a pipeline for 10 shifts without intervention from a mentor, students were considered qualified operators.

Operator training emphasized individual knowledge, skills, and performance. Enbridge did not conduct team training involving shift leads, operators, and MBS analysts, nor did PHMSA or the NEB require such training. According to Enbridge, although it did not conduct formal team training programs, control center operators were introduced to team aspects of the control center during initial training and were expected to rely on available control center staff to accomplish training objectives. When operators were introduced to simulator scenarios, instructors and other course participants used role playing to assist or distract the operator trainees, portraying, for example, on-site or on-call field personnel. According to Enbridge, part of the evaluation of student performance was based on the quality of the student's teamwork.

After qualifying, operators and shift leads participated annually in simulator training where they were presented with leak and column separation scenarios, as well as other abnormal operating conditions. PHMSA required operators to demonstrate their technical knowledge and pipeline operating proficiency on a regular basis through an evaluation process known as operator qualification. Enbridge conducted operator qualifications at 3-year intervals, in accordance with PHMSA regulations. PHMSA did not require, nor did Enbridge regularly evaluate, the technical proficiency of shift leads, MBS analysts, or other control center supervisors or managers.

Many of the operators told NTSB investigators that the emergency scenarios were the only occasion they had to observe a leak scenario after completing their initial training. One operator described the emergency scenarios they practiced in the following manner, "They have some preconfigured programs that we run and some of them have station lockouts and some of them have leaks and some of them have just com [communications devices] fails and different scenarios that we go through to help us to understand what we're seeing." The operator added that they practice leak scenarios on the simulator, but, because the simulators do not have MBS alarms, they recognize leaks by line pressure variations.

According to Enbridge's control center supervisor, applicants for control center operator positions came from two groups: (1) graduates with degrees in engineering technology from 2-year technical schools in Alberta and (2) people with experience as control center operators. Enbridge gave applicants written tests and simulator exercises, and those who performed satisfactorily were interviewed by control center supervisors and managers. Interviews sought to determine the ability of applicants to perform satisfactorily with others in Enbridge's control center.

1.11.4.2 MBS Analyst

MBS analyst training typically takes 3 months to complete. According to Enbridge's director of the pipeline modeling group, the curriculum contained two instructional segments: (1) learning basic hydraulic information and the Enbridge MBS and (2) participating in on-the-job training and observing qualified MBS analysts perform their duties. In addition, students practiced scenarios on a simulator and determined the validity of MBS alarms.

Upon successfully completing a written examination and a performance assessment on a simulator-presented scenario, students were considered qualified as MBS analysts.

1.11.5 MBS Leak Detection

1.11.5.1 Federal Regulations

PHMSA requires pipeline operating companies to have effective leak detection methods under 49 CFR 195.452(i)(3), “An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the HCA. An operator’s evaluation must, at least, consider, the following factors—length and size of the pipeline, type of product carried, the pipeline’s proximity to the HCA, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.” In addition, 49 CFR 195.134 requires that each hazardous liquid pipeline transporting liquid in single phase, with an existing CPM system, comply with section 4.2 of API RP 1130 in its design. Title 49 CFR 195.444 requires that the CPM system be compliant with API RP 1130 with respect to operating, maintaining, testing, record-keeping, and dispatcher training.

1.11.5.2 API 1130 Computational Pipeline Monitoring for Liquids

API’s RP 1130⁷² for CPM of liquid lines offers guidance to pipeline operating companies on how to establish and to operate CPM leak detection systems. This RP addresses technology, infrastructure, SCADA, data presentation, system integration with SCADA, CPM operations, and system testing. The RP addresses the use of a support person to help a control center operator distinguish between types of CPM alarms. The RP states,

The causes of the Pipeline Company CPM Alarms are not usually determined by a separate piece of software, (i.e. an expert system) that provides the cause or probability of cause, but by the Pipeline Controller or CPM support person. Simply understanding the cause of the alarm condition on a monitored pipeline may not be the end of the alarm evaluation.

According to the RP, the CPM system should use three alarms to help “justify the CPM system credibility and sensitivity of the CPM system.” The RP further states,

Many CPM systems provide just one type of alarm and so in this case the determination of the cause and categorization of alarm should be made by the person who evaluates the alarm (the Pipeline Controller or perhaps jointly with a CPM support person) or by a separate piece of software (i.e. an expert system) that provides the cause or probability of cause. Automatic alarm cause evaluation would be a desirable CPM system feature.

⁷² API RP 1130, *Computational Pipeline Monitoring for Liquids*, third edition, September 2007.

The Edmonton control center staff relied on the MBS analyst as their support person for MBS alarm evaluation.

The RP states that past instances of alarm causes can be a useful guide in alarm evaluation but every alarm should be evaluated individually and assumptions of previous causes should not be readily made. API's RP 1130 further emphasizes the need for review of past CPM alarms when they become excessive so as to maintain CPM credibility, "an excessive number of alarms will detract from the system credibility and may create complacency."

API's RP 1130 states that a CPM alarm is probably the most complex alarm that a control center operator will experience. To correctly recognize and respond to this type of alarm, the RP states that an operator needs specific training and appropriate reference material.

1.11.5.3 Enbridge's MBS

Enbridge's MBS software was one of several leak detection methods Enbridge used. Additional leak detection methods included aerial patrols, emergency hotline calls, a batch tracking system, and SCADA data.

At the time of the accident, the Enbridge MBS used a real-time pressure transient pipeline model, which operated in parallel with the SCADA system and consisted of a hydraulic model with the actual pipeline's attributes.⁷³ The MBS software incorporated real-time pressure, flow, temperatures, and density from the SCADA and the batch-tracking system to calculate an expected flow and pressure between the pipeline sections and then compare those values to the actual flow meter readings. The system monitors volume imbalances between the estimated and actual flows in the pipeline. One flow meter installed along the mainline at the Marshall PS, divided Line 6B into two separate volume balance sections: (1) the Griffith Terminal to the Marshall PS, and (2) the Marshall PS to the Sarnia Terminal. Additional flow meters were installed at the delivery and injection terminals. During times of stable operation, the MBS relied upon both flow measurement and pressure data to calculate imbalances. Losing one or the other would affect the level of accuracy.

When the volume imbalance of the MBS software exceeded the alarm or threshold value, an audible alarm and visual alert were displayed to the control center operator⁷⁴ that required interpretation by an MBS analyst. The shift lead and control center operators had a limited set of MBS displays, including pipeline elevation and hydraulic gradient profiles; however, operator A1 and shift lead B2 told investigators they were not familiar with the MBS console displays and were not trained to use the MBS software. Enbridge used a single MBS alarm indication that displayed as a 5-minute, 20-minute, or 2-hour alarm (the shorter the time, the larger the leak indication). A second alarm sounded when the condition continued for more than 10 minutes.

⁷³ This included diameter, length of line, valves, fittings, PSs, and elevations.

⁷⁴ Enbridge's SCADA system used only one sound for all alarms, regardless of pipeline condition or urgency of operator action needed in response.

Because the MBS software relied on SCADA pressures and flow meter readings, transient operations such as shutdowns and startups could impact the MBS software's leak detection capabilities. MBS analyst B also stated that the shift leads were aware that when column separation was present, the MBS software was "not reliable." The supervisor of the MBS group told investigators that it was commonly known that MBS alarms clear upon shutting down a pipeline.

The Enbridge MBS procedure (that is, flowchart) indicates that when column separation is present, the MBS software is unreliable. As explained by an Enbridge MBS specialist and MBS analyst B, the MBS software is no longer able to predict the pipeline performance accurately so the MBS analyst does not believe the MBS software when there is column separation present in a pipeline segment. Just because an MBS event clears in the SCADA system, it does not mean the underlying condition has been resolved. Column separation is a known limitation to pressure transient leak detection systems because the systems are built to estimate the flows and pressures of a homogenous liquid line.

MBS analyst B told investigators that over a typical 12-hour shift, three of five calls were due to column separation. According to Enbridge, calls to the MBS analyst to research MBS alarms averaged from 1.6 to 4.2 calls per shift in 2010. More than one operator interviewed stated that a majority of the MBS alarms were related to either column separation or instrumentation. Historical alarm records showed that no MBS alarms attributed to column separation occurred on Line 6B before the pressure restrictions were implemented at the Marshall PS in July 2009. Following the 2009 pressure restrictions, the control center reported three MBS alarms⁷⁵ associated with column separation. None of the reported column separation indications were near the Marshall PS or ruptured pipe segment.

During the initial startup on July 26, 2010, the MBS analyst B had to override the pressures in the MBS software⁷⁶ to reflect actual conditions at the Niles PS because the MBS system did not reflect the closed valves. A second pressure transmitter at the Stockbridge Terminal (downstream of Marshall) had been disabled in the MBS software on July 22 and re-enabled at 10:00 p.m. on July 25, 2010.

1.11.5.4 Column Separation

Column separation, sometimes called slack line, commonly occurs in areas of higher elevation where the line pressure is lowest on a pipeline; however, column separation can occur at any point in a pipeline where the pressure in the line is below the pressure at which the oil becomes a vapor⁷⁷ resulting in liquid-and-vapor mix. The vapor within the pipeline forms a void that restricts the flow of liquid. Any void in the internal volume of the pipeline, including a large

⁷⁵ These alarms occurred on October 18, 2009; April 28, 2010; and June 27, 2010. All of the MBS alarms were in the Marshall PS to the Stockbridge PS section with column separation indications at the Marysville Terminal, downstream of the Stockbridge PS.

⁷⁶ The Niles PS pressure transmitters used by the MBS were located behind the isolation valves that were shut when the station was taken out of service for the in-line inspection tool; therefore, the pressure readings were disabled in the MBS software following the shutdown on July 25, 2010.

⁷⁷ The point at which a liquid turns to vapor is a function of both temperature and pressure and is referred to as the vapor pressure of the liquid.

loss of oil either from a rupture or drain off into lower elevations, would result in column separation indications over the leak detection software. The terrain between the Marshall PS and the next PS was relatively flat with a net elevation rise between the two of about 30 feet and a maximum rise of 100 feet. To eliminate column separation, pressure must be increased above the vapor pressure of the liquid.⁷⁸ This may require generating back pressure in the line by closing a downstream valve or increasing the delivery rate or pressure from an upstream PS.

1.11.6 Procedures

1.11.6.1 10-Minute Restriction

Multiple control center operational procedures reference a restriction to operation of the pipeline in excess of 10 minutes when operating under unknown circumstances. The 10-minute limit appears in the control center *Suspected Column Separation*, *MBS Leak Alarm-Analysis by MBS Support*, and *Suspected Leak* procedures, among others and was commonly referred to in the control center as the “10-minute rule.”

The 10-minute limitation was adopted as a result of the March 1991 Enbridge rupture and release that occurred on Line 3, spilling 1.7 million gallons of crude oil in Grand Rapids, Minnesota.⁷⁹ The oil release polluted a tributary of the Mississippi River with a reported cleanup cost of \$7.5 million. The failure occurred in fatigue cracks at the base of the DSAW longitudinal seam weld (where the weld meets the body of the pipe). During the 1991 accident, personnel in Enbridge’s Edmonton Control Center interpreted the SCADA alarms and indications to a condition of column separation and instrument error and continued to pump oil into the ruptured 34-inch-diameter line for more than an hour until the leak was recognized.

In 1991, Enbridge stated in its response to PHMSA that a revision to the operation maintenance procedures manual was adopted stating, “If an operator experiences pressure or flow abnormalities or unexplainable changes in line conditions for which a reason cannot be established within a 10-minute period, the line shall be shut down, isolated, and evaluated until the situation is verified and or [sic] corrected.”

1.11.6.2 Suspected Column Separation

The control center’s suspected column separation procedure (see appendix B) required that the control center operator notify the shift lead in the event of a suspected column separation. According to the procedure, if the column separation had not been restored within 10 minutes, the control center operator was to notify the shift lead, shut down the pipeline, close the mainline valves and record the event electronically as an abnormal operation. The shift lead had the responsibility of making emergency notifications to the field and having field personnel confirm a leak. If no leak were found then the line could only be restarted with permission from the pipeline control on-call designated supervisor.

⁷⁸ According to Enbridge, on the evening of the rupture, Cold Lake crude was being pumped through Line 6B, which has a stated vapor pressure below atmospheric pressure.

⁷⁹ PHMSA investigated this accident.

A draft version of the suspected column separation procedure was sent out to control center staff for review in May 2010. The draft version of the procedure included a new section to the existing procedure addressing “starting up into a known column separation.” Under the draft procedure, the control center operator was to notify the shift lead of the column separation and calculate an estimated time to restore the column prior to starting the pipeline. Under known column separation procedure, the 10-minute restriction became effective only after the estimated time to restore the column had expired.

According to operator B2, the draft procedure was used once prior to the accident, when starting a pipeline that had been intentionally drained into storage tanks. According to shift lead B1 who used this procedure during the first startup, he believed that there had been an excessive volume lost due to drainage to lower elevations and delivery locations after the shutdown. He had also attributed volume lost to a valve that had been opened at the Marysville Terminal delivery location during startup that morning. Shift lead B1 stated that he was aware that this was a draft procedure.

1.11.6.3 MBS Alarm

According to the control center procedures on leak alarms, the control center operator notified the shift lead and recorded the event as an abnormal operation in the facility and maintenance database. The shift lead had the responsibility of assessing the alarm and calling it a temporary alarm or notifying the MBS analyst to review the alarm. Shift leads nearly always gave the MBS alarms to the MBS analyst for review. The procedure required that the control center operator shut the line down if an analysis of the MBS alarm was not complete within 10 minutes. The control center staff expected that either the MBS analyst would report the alarm as “valid” or “false”; however, these terms do not appear in the MBS flowchart for examining MBS alarms. Temporary or false alarms resulted in the pipeline being allowed to start again or resume normal operations without approval. Valid alarms required approval of the on-call supervisor or regional management to start the pipeline.

MBS analyst B told investigators that “valid” and “false” were control center terms and were not used by MBS analysts. According to the Enbridge flowchart⁸⁰ used by the MBS analyst, if the MBS software showed that vapor was present in the pipeline, the MBS analyst was to contact the shift lead and tell the shift lead that the software was showing column separation but that the software was not reliable. The Enbridge flowchart directed the MBS analyst to tell the shift lead that it was the control center operator’s decision to start the line. After the accident, MBS analyst B told investigators that it was the operator’s job to examine the pressures on the pipeline to determine if there was a leak or not.

1.11.6.4 SCADA Leak Triggers

The Enbridge control center procedures included a leak triggers list, that is, indications in the SCADA system of possible leaks. The procedure defined leak triggers as unexplained, abnormal operating conditions or events that indicate a leak. Enbridge included suspected

⁸⁰ See Enbridge’s MBS and control center operations procedures provided in appendix B of this report.

column separation, MBS alarms, MBS malfunction, leak triggers from SCADA data, a suspected leak from SCADA data, and sectional valve alarms as some of the conditions constituting abnormal events that required reporting to management.

The control center operator was to use the suspected leak procedures to determine whether a leak was present on the pipeline through SCADA indications. Leak triggers included active MBS alarms, sudden drops in discharge or suction pressure, sudden increases or decreases in flow rate, and the local shutdown of PSs in combination with pressure drops. One or two leak triggers required that the suspected leak procedure be followed, which monitored the line conditions for further leak triggers. If a leak could not be ruled out in 10 minutes then the line was to be shut down. Three or more leak triggers required the immediate shutdown of the pipeline and emergency notifications to the field under the confirmed leak triggers procedure.

1.11.6.5 Suspected Leak—Volume Difference

A suspected leak procedure for volume differences associated with pipeline estimates performed by the control center operator from the commodity movement and tracking system (CMT)⁸¹ stated that if the difference between the volume injected into the pipeline and the volume received at the terminals is more than 10 percent, or if the volume imbalance was not accompanied by a corresponding increase in pipeline pressures, the confirmed leak procedure was to be executed.

1.11.6.6 Leak and Obstruction Trigger—On Startup from SCADA Data

The leak and obstruction trigger procedure required that the control center operator review the holding pressures on a pipeline segment if the pressure changes did not propagate throughout a pipeline segment within a specified time (about 1 minute). If sufficient holding pressure was maintained on the pipeline segment during shutdown, the control center operator was to execute the procedure for a confirmed leak. If insufficient holding pressure was maintained on a pipeline during shutdown, the control center operator was to execute the procedure for suspected column separation.

1.11.7 Fatigue Management

Title 49 CFR 195.446(d), regarding methods to reduce the risk of control center operator fatigue, was effective on November 30, 2009, and required procedures to be in place by August 1, 2011, and implemented by February 1, 2012. Enbridge developed and distributed a fatigue risk management plan that took effect on July 30, 2011. PHMSA’s regulations governing hours of service required pipeline control center operators to receive at least 8 hours of rest between shifts. Enbridge followed PHMSA requirements to provide operators with “off-duty time sufficient to achieve eight hours of continuous sleep” and limited emergency coverage to seven 12-hour shifts in succession. According to Enbridge’s control center supervisor, control

⁸¹ At Enbridge, CMT is a system that performs real-time monitoring of the oil in the pipeline. Control center operators manually perform an accounting of the volumes of oil in the pipeline every 2 hours to check delivery volumes and potential leaks.

center shifts were 12 hours long, although operators worked overtime beyond those 12 hours on occasion. Thus, a typical control center operator's schedule began at 8:00 a.m.⁸² on Friday, Saturday, and Sunday, ending at 8:00 p.m. each day, followed by Monday and Tuesday nights in which the schedule was reversed. After 4 to 5 days off duty, the operator would then work 2 nights followed by 3 days, or 3 days followed by 2 nights, scheduled in such a way as to preclude anyone from working without at least 24 hours of rest when alternating between night and day shifts.

1.11.8 Enbridge Health and Safety Management System

Prior to this accident, Enbridge implemented a health and safety management system, which primarily pertained to on-site safety. In May 2010, Enbridge created the position of director of safety culture after three pipeline employees had been killed in two on-site accidents in the 5 months between November 2007 and March 2008. This position, which reported to the senior vice president of operations, was given to Enbridge's director of construction, safety, and services within its major project group. The focus of the program was in the areas of workplace safety, process safety management, and contractor safety. Within these areas, the company concentrated on five general safety areas: driving safety, confined space entry, ground disturbance, isolation of energized systems, and reporting of safety-related incidents.

In November 2008, the company retained the services of a consultant to produce a safety benchmarking assessment.⁸³ The director of safety culture stated that after the Marshall accident, Enbridge realized that safety encompassed more than workplace safety and individual safety, and the company began to develop a better understanding of the need for process safety management and also the need to make sure that control center operations were included within the scope of the safety culture. There is no PHMSA requirement for pipeline operating companies to implement safety management systems (SMS).

1.12 Environmental Response

1.12.1 Volume Released

At the time of the rupture, two batches of crude oil were located in the pipeline on either side of the rupture location. These were 2.6 million gallons of Cold Lake Blend and 2.7 million gallons of Western Canadian Select crude oil. When Enbridge first notified the NRC about the rupture and release, it reported that an estimated 819,000 gallons of oil had been spilled. NTSB investigators learned that this was an inaccurate estimate based on the wrong diameter pipe. Enbridge performed a second analysis, which included oil lost from higher elevations as well as pumped volumes during the two startups. Based on this analysis, on November 2, 2010, Enbridge revised its estimated release volume to 843,444 gallons. The NTSB examined flow meter trends from the SCADA system for injected volumes of oil at Griffith Terminal during the two Line 6B startups on July 26, 2010. Based on this examination, the NTSB determined about

⁸² This is expressed in eastern daylight time for the report; 8:00 a.m. eastern daylight time is 6:00 a.m. local Edmonton time.

⁸³ This was the second such assessment after an initial one in May 2005.

683,436 gallons (81 percent of the total release) of crude oil were pumped into Line 6B during the two startups. (See appendix C).

1.12.2 Hazardous Materials Information

Cold Lake Blend and Western Canadian Select crude oil condensate mixtures⁸⁴ are regulated by the U.S. Department of Transportation (DOT) as class 3 flammable hazardous materials. Heavy crude typically is a mixture of crude oil (from 50 to 70 percent) and hydrocarbon diluent⁸⁵ (from 30 to 50 percent). The material contains 20 to 30 percent volatiles by volume. The mixture is used as raw material in the production of fuels and lubricants. It is a brown or black liquid with a hydrocarbon odor; it is lighter than water with a specific gravity of 0.65 to 0.75. It exhibits a flashpoint of -31° F. The vapor is heavier than air, with a lower explosive limit of 0.8 percent and an upper explosive limit of 8 percent vapor concentration in air.

1.12.3 Overview of the Oil Spill Response

During the first day of the response, the Marshall PLM responders were assisted by contractors and regional personnel. Late on the first day of the response, the first responders constructed an underflow dam in the wetland near the source area and installed additional oil sorbent and containment boom in the Kalamazoo River at Heritage Park and at Linear Park in Battle Creek, about 8.9 and 14.8 miles downstream of the rupture, respectively. On July 26, Enbridge also deployed vacuum trucks to recover oil from the source area underflow dam, from the Talmadge Creek stream crossings on Division Drive and 15 1/2 Mile Road, and from the Kalamazoo River at Heritage Park. (See table 4.)

Table 4. Enbridge resources deployed as reported at midnight on July 26, 2010.

| Location | Resources Deployed | Personnel |
|------------------|--|--------------------------------------|
| Leak site | One underflow dam, vacuum trucks ^a | 7 Enbridge |
| 15 1/2 Mile Road | One skimmer, 30-ft oil boom, three vacuum trucks | 4 Enbridge |
| Division Drive | Two, 50-ft oil boom, two vacuum trucks | 14 Enbridge 10 Contractors (est.) |
| A Drive North | 50-ft oil boom, one vacuum truck | |
| Heritage Park | 600-ft oil boom, two vacuum trucks | |
| Linear Park | 400-ft oil boom, one vacuum truck | |

^a The number of vacuum trucks servicing the underflow dam was not tracked on the first day of the response, although Enbridge reports as many as three trucks were pumping at the same time.

⁸⁴ Without the addition of condensate, heavy bituminous crude oil does not flow easily.

⁸⁵ Hydrocarbon diluent is a substance used to dilute a viscous or dense substance so that it will flow more easily.

During the first week of the response, Enbridge assigned between 29 and 36 workers (day) and 22 to 26 workers (night) to river oil containment operations. These workers were supplemented with as many as 356 day personnel and 160 night personnel that were employed by private oil spill response organizations.

In the days following the accident, Enbridge and its contractors established about 33 oil spill containment-and-control points (from the release site to the west end of Morrow Lake in Kalamazoo County, covering about 38 miles of the river). (See figure 19.) The control points consisted of a variety of oil containment strategies, including underflow dams, oil booming, and sorbent booming. Vacuum trucks and oil skimmers were used to remove oil at these locations.

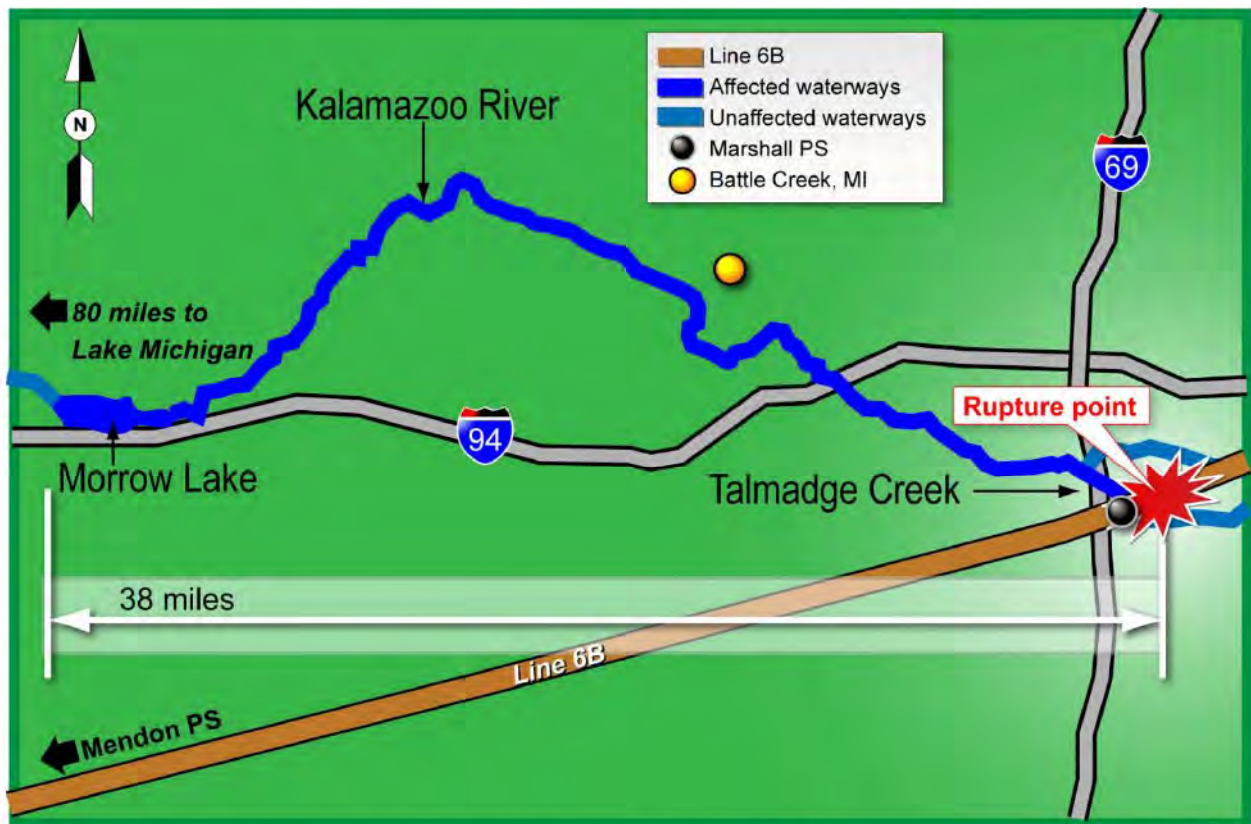


Figure 19. Map showing rupture location and affected waterways from Talmadge Creek to Morrow Lake.

By July 29, the third day of operations, 51,090 feet of oil boom had been deployed and 647 field personnel were on site. On August 17, the peak deployment of 2,011 personnel occurred. The greatest amount of oil boom deployed in the affected waterways was 176,124 feet, which was deployed on August 20.

As of April 30, 2012, the EPA reported that over 17 million gallons of oil and water liquid waste had been collected, from which an estimated 1.2 million gallons of oil had been recovered by the spill response contractors. In addition, about 186,398 cubic yards of hazardous and nonhazardous soil and debris were disposed of, including river dredge spoils.

1.12.3.1 Notifications

The Enbridge supervisor of regional engineering initially contacted the NRC about 1:09 p.m. on July 25, 2010; however, his call was placed on hold for about 6 minutes. He called the NRC again about 1:23 p.m. and was placed on hold before he was able to report the release about 1:33 p.m. Between 1:47 and 1:49 p.m., the NRC notified 16 Federal and Michigan state agencies, including the EPA, the U.S. Coast Guard (Coast Guard), PHMSA, the Michigan Department of Environmental Quality, the Michigan Intelligence Operations Center, and the Michigan Department of Community Health.

1.12.4 Enbridge Facility Response Plan

Each operator of an onshore pipeline, for which a response plan is required by 49 CFR 194.101, may not handle, store, or transport oil in a pipeline unless the operator has submitted a response plan that meets the requirements of this regulation. Every 5 years, pipeline operating companies must review, update, and resubmit facility response plans to PHMSA for approval.

The response plan must address a worst-case discharge, identify environmentally and economically sensitive areas, and describe the responsibilities of the operator and Federal, state, and local agencies in removing such a discharge. Title 49 CFR 194.115(a) states, “Each operator shall identify and ensure, by contract or other approved means, the resources necessary to remove, to the maximum extent practicable, a worst case discharge and to mitigate or prevent a substantial threat of a worst case discharge.” Title 49 CFR 194.115(b) directs pipeline operating companies to identify in their response plans the response resources that are available to respond within the time-specific response tiers after discovery of a worst-case discharge, as shown in table 5.

Table 5. Title 49 CFR 194.115 response tiers.

| | Tier 1 | Tier 2 | Tier 3 |
|------------------|----------|----------|----------|
| High volume area | 6 hours | 30 hours | 54 hours |
| All other areas | 12 hours | 36 hours | 60 hours |

The regulation does not provide guidance for determining the amount of response resources that should be on site within the Tier 1, 2, and 3 timeframes. In the absence of guidance, Enbridge developed its own interpretation of the three-tier requirement.

The Enbridge senior compliance specialist told NTSB investigators that Tier 1 refers to resources that provide initial containment and recovery efforts, such as Enbridge equipment and personnel that are available from the nearest PLM facilities. Tier 2 includes Enbridge’s internal emergency response resources from anywhere within the Chicago region in addition to those local contractors listed in the Enbridge emergency response directory. Tier 3 consists of oil spill response organizations that are identified in the facility response plan. Even with Enbridge’s definitions of the tiered resources, an Enbridge North Dakota Region supervisor of measurement,

audit, and compliance stated that the regulation was vague and lacking in guidance for the level of response required for each tier.

On February 23, 2005, PHMSA published a final rule establishing oil spill response planning requirements for onshore oil pipelines in accordance with 49 CFR Part 194.⁸⁶ The final rule purported to harmonize certain PHMSA requirements with related oil spill response regulations developed by the Coast Guard. PHMSA received several comments on its interim final rule published in 1993 expressing concern that 49 CFR 194.115 does not identify the level of capability that PHMSA would consider sufficient within the three tiers. In the final rule, PHMSA did not amend the response resources requirement to include specific tiered response planning criteria.

Enbridge determined that pipeline facilities within its Chicago response zone met the significant and substantial harm criteria outlined in 49 CFR 194.103 and developed a *Chicago Region Specific Emergency Response Plan (#867)*, most recently revised on April 10, 2010. The Chicago response zone covers 11 pipelines and 3 terminal lines that transport crude oil, diluents, and natural gas liquids within 2,108 miles of pipeline. The accident involved the approximate worst-case discharge of 1,111,152 gallons specified in Enbridge's facility response plan⁸⁷ for Line 6B. The worst-case discharge is based, in part, on the maximum flow rate of the pipeline and an assumed response time of 8 minutes, the time allotted for the control center to recognize a leak and close the necessary valves.

Enbridge's plan states that the company owns and maintains emergency response equipment throughout its Chicago region at 13 office locations and strategic locations, including the Marshall, Michigan, PLM shop. The plan lists the amounts and types of spill response equipment maintained at each PLM station for responding to a worse-case discharge, including the Marshall PLM. According to the plan, the single Marshall PLM inventory response trailer (see figure 20) was packed with 1,100 feet of river containment boom; 200 feet of small containment boom; 200 feet of sorbent boom; and 1,000 sorbent pads to respond to the stated worst-case discharge of 1,111,152 gallons. In addition to the trailer, the PLM shop equipment included 3 skimmers, 18 pumps, 1 storage tank, 3 boats, and a single 1,680- to 2,520-gallon-capacity vacuum truck. According to Enbridge's interpretation of response planning regulations, this equipment constitutes its Tier 1 response resources.

⁸⁶ *Federal Register*, vol. 70, no. 35 (February 23, 2005), p. 8734.

⁸⁷ The worst-case discharge takes into account the design flow rate and the time to shut down the pipeline plus the amount released due to the elevation profile. The Enbridge response plan identified Line 6B as having a design capacity of 12.6 million gallons per day with an estimated time to recognize a leak and shut down valves of 8 minutes.



Figure 20. Enbridge PLM emergency response trailer containing the company's Tier 1 oil containment equipment, October 17, 2010.

According to its facility response plan, Enbridge employed 112 hazardous waste operations and emergency response-trained pipeline personnel and technicians who are available for emergency response to oil releases in the company's Chicago region. The plan stated that Enbridge has working agreements with Bay West and Garner Environmental Services, Inc. to supplement Enbridge's resources to respond to a worst-case discharge. Bay West, based in Minneapolis, Minnesota, is an established Coast Guard oil spill response organization that provides 24-hour emergency spill response. Garner Environmental Services, Inc., based near Houston, Texas, advertises that it has numerous locations and many away teams, which are capable of providing timely response upon notification. Enbridge maintained lists of other local contractors that may be used for emergencies in each Enbridge response zone.

When notified of the Marshall accident, Bay West assembled its available resources, including 20 response personnel equipped with one boat and one trailer containing spill response equipment. After a 10- to 11-hour drive, Bay West's crews arrived on July 27. Garner Environmental Services, Inc.'s crews arrived by Thursday, July 29.

Enbridge's facility response plan referred to control point maps that Enbridge had developed for use during spill response activities. The maps provided emergency responders

with a reference to accessible locations for deploying containment boom. The two mapped locations closest to Talmadge Creek on the Kalamazoo River were not accessible to the responders because of the heavy rains that had increased the water levels, and a containment boom was not deployed.

1.12.5 EPA Oversight of Spill Response Efforts

On July 26, 2010, about 1:40 p.m., an EPA official in the EPA's Region 5 Chicago office verified the information contained in Enbridge's report to the NRC. About 1:51 p.m., the EPA official contacted two other on-scene coordinators and advised them to respond to the accident to verify the content of the NRC report and to initiate response activities as necessary. About 4:32 p.m., the first EPA on-scene coordinator arrived and saw the oil in Talmadge Creek from the Division Drive crossing and concluded that the oil spill was significant. He observed one vacuum truck but no oil boom on the discharge side of the culvert under Division Drive.

EPA on-scene coordinators attempted to collect information about the Enbridge response effort but noted that the Chicago regional manager was not able to provide sufficient information about either the company's response actions or the amount of resources it had deployed. The EPA response effort on July 26 consisted primarily of monitoring Enbridge's emergency response activities.

At the end of the first day of the response, the EPA on-scene coordinators stressed that Enbridge should make all efforts necessary to protect a Superfund⁸⁸ site, which extended about 80 miles from the Morrow Lake Dam to Lake Michigan to prevent comingling of the contaminants. The EPA on-scene coordinators directed that oil boom be installed 30 miles downstream of the rupture at Morrow Lake as a collection point. About 8:40 p.m., the senior on-scene coordinator contacted the EPA Region 5 emergency response branch chief and requested mobilization of an incident management team, the Superfund Technical Assessment and Response Team,⁸⁹ and Emergency and Rapid Response Services⁹⁰ contractors.

The EPA on-scene coordinators told NTSB investigators that they determined during the initial hours of the response that Enbridge did not have the resources on site to contain or control the flow of oil into Talmadge Creek and the Kalamazoo River. The EPA directed Enbridge to secure more resources for the response. Upon learning that some crews were responding from Minnesota, an on-scene coordinator provided Enbridge the names of local contractors to facilitate a quicker response time.

⁸⁸ Superfund is the name given to the environmental program established to address abandoned hazardous waste sites under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Superfund allows the EPA to clean up sites and to compel responsible parties to perform cleanups or reimburse the government for EPA-led cleanups.

⁸⁹ The Superfund Technical Assessment and Response Team contractors provide technical support to EPA's site assessment and response activities, including gathering and analyzing technical information, preparing technical reports on oil and hazardous substance investigations, and technical support for cleanup efforts.

⁹⁰ The Emergency and Rapid Response Services contractors provide the EPA with time-critical cleanup services, including personnel, equipment, and materials to contain, recover, and dispose of hazardous substances. The contract also provides for sample analyses and site restoration activities.

About 8:15 p.m. on July 27, the Federal on-scene coordinator (FOSC)⁹¹ issued an administrative removal order to Enbridge's chief executive officer under Section 311(c) of the Clean Water Act (33 U.S.C. 1321(c)), requiring the company to stop the flow of oil into the Talmadge Creek and the Kalamazoo River, to remediate all oil and contaminated soils in and around the vicinity of the release, and to deploy appropriate oil recovery and containment devices and equipment. The administrative order also required Enbridge to conduct other activities such as air, water, and sediment sampling, and waste disposal at approved facilities.

1.12.6 Environmental Monitoring

1.12.6.1 Air Quality

On July 26, EPA monitored the air along the Kalamazoo River, in residential areas bordering Talmadge Creek, and at Morrow Lake. The highest concentrations of volatile organic compounds—organic compounds that have a high vapor pressure at normal temperatures causing them to evaporate readily, many of which are dangerous to human health—occurred at crossings of 15 1/2 Mile Road and A Drive North over Talmadge Creek and at the 15 Mile Road bridge crossing over the Kalamazoo River.

Between July 27 and 29, the levels of benzene and petroleum hydrocarbons were sufficient to require respiratory protection for the cleanup workers.

1.12.6.2 Potable Water

On July 29, the Calhoun County Health Department and the Kalamazoo County Health and Community Services Department issued an advisory to residents with private wells within 200 feet of the Kalamazoo River and Talmadge Creek to stop using the water for drinking and cooking.

On September 23, 2010, the EPA issued a supplemental order that required (in part) that Enbridge sample all private and public drinking water wells located within 200 feet of all impacted waterways and that Enbridge evaluate potential impacts to groundwater. On October 31, 2010, Enbridge submitted its evaluation report to local health departments. After review of the report and drinking water sampling results collected to date, the local health departments lifted the drinking water advisory.

1.12.6.3 Surface Water and Sediment

The EPA ordered Enbridge to sample the surface water and the sediment of the impacted areas by July 27, 2010, and continuously thereafter until notified by EPA. The waters from Talmadge Creek and the Kalamazoo River, from the confluence point of Talmadge Creek to Morrow Lake, were contaminated to varying degrees with petroleum-related hydrocarbons. Once the crude oil mixture entered the water, weathering, volatility, and physical agitation caused the

⁹¹ The FOSC is the Federal official responsible for coordinating and directing responses to discharges of oil into waters of the United States.

denser oil fraction to sink and incorporate into river sediments and collect on the river bottom. As of January 2012, the Michigan Department of Environmental Quality continued to evaluate water quality in the affected river system.

On August 1 and 3, 2010, respectively, the Kalamazoo and the Calhoun County health departments prohibited the use of these surface waters for irrigation and the watering of livestock. Calhoun County's ban also applied to recreation activities, including boating, swimming, fishing, and the agricultural use of surface waters.

The Michigan Department of Community Health advised members of the public not to consume fish from either Talmadge Creek or the Kalamazoo River to the west end of Morrow Lake. The Kalamazoo County Health and Community Services partially lifted the water use ban on September 3 in response to improved water sampling test results for the portion of the Kalamazoo River between Morrow Dam and Merrill Park.

Enbridge began collecting sediment samples on July 27 to determine the impact of the spill on the river system. By August 2010, field personnel noticed the presence of submerged oil. Starting in September 2010 and continuing throughout the winter, Enbridge removed the submerged oil by dredging, excavating, and aeration. In spring 2011, an EPA-directed reassessment found a moderate-to-heavy contamination covering over 200 acres of the river bottom. In August 2011, the EPA directed Enbridge to remove the remaining submerged oil. On June 21, 2012, the responding local, state, and Federal agencies announced that impacted areas of Talmadge Creek and the Kalamazoo River, except for Morrow Lake Delta, are open for recreational use.

1.12.7 Natural Resources and Wildlife

With the cooperation of U.S. Fish and Wildlife Service and the Michigan Department of Natural Resources and Environment, Enbridge established a wildlife response center in Marshall to accept and treat affected wildlife. The wildlife response center cared for and released about 3,970 animals, including about 3,650 reptiles and 196 birds. Of the 196 birds treated, 144 were released.

The National Oceanic and Atmospheric Administration coordinated with Federal and state agencies and Enbridge to collect data on the oil-impacted natural resources for a natural resources damage assessment, as required by the Oil Pollution Act of 1990. The study has not yet been completed.

1.13 Previous NTSB Investigations and Studies

1.13.1 NTSB SCADA 2005 Study

In 2005, the NTSB conducted a safety study of SCADA systems for hazardous liquid pipeline operators,⁹² examining the design and staffing of SCADA centers and operational issues

⁹² *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines*, Safety Study NTSB/SS-05/02 (Washington, D.C.: National Transportation Safety Board, 2005).

such as SCADA screen graphics, alarm design, fatigue management, controller training and selection, and CPM (leak detection). The study examined the role of SCADA systems in 13 hazardous liquid line accidents investigated between 1992 and 2004. In 10 of the accidents cited by the study, there was a delay in leak recognition by the control center operators. The NTSB issued a report on November 29, 2005, with five recommendations to PHMSA, which included that PHMSA require use of API's RP 1165 for SCADA graphics, pipeline operators review/audit SCADA alarms, that control center operators receive simulator or noncomputerized abnormal operating condition training, that liquid pipeline operators report fatigue information on the PHMSA accident report form and that all pipeline operators install computer based leak detection systems. The 2005 NTSB report concluded that the use of a leak detection technology would enhance the control center operator's "ability to detect large spills, increase the likelihood of spill detection, and reduce the response time to large spills." Partially in response to the study, Public Law 109-468, the Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act of 2006, was enacted on December 29, 2006. To conform to these recommendations and the requirements of the PIPES Act, PHMSA created the control center management rule contained in 49 CFR Parts 192 and 195. As a result, the NTSB closed the recommendations and classified them, "Closed—Acceptable Action."

1.13.2 NTSB 2010 Pipeline Investigation of Pacific Gas and Electric Company

On September 9, 2010, a gas pipeline in San Bruno, California,⁹³ operated by the Pacific Gas and Electric Company (PG&E), ruptured. Eight people were killed, 10 were injured seriously, 48 people sustained minor injuries, and 38 houses were destroyed. In its investigation of this accident, the NTSB identified a lack of team performance within PG&E's SCADA operations center after the rupture. The report noted,

...that the lack of assigned roles and responsibilities resulted in SCADA staff not allocating their time and attention in the most effective manner. ...The lack of a centralized command structure was also evident in that key information was not disseminated in a reliable manner. ...The lack of a centralized command structure was also reflected in the conflicting instructions regarding whether to remotely close valves at the Martin Station. ...Finally, the supervising engineer for the SCADA controls group seemed slow to get involved, despite the fact that he is responsible for all SCADA and control systems throughout the PG&E gas transmission pipeline system. ...In summary, PG&E's response to the Line 132 break lacked a command structure with defined leadership and support responsibilities within the SCADA center. Execution of the PG&E emergency plan resulted in delays that could have been avoided by better utilizing the SCADA center's capability.

⁹³ *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010*, Pipeline Accident Report NTSB/PAR-11/01 (Washington, D.C.: National Transportation Safety Board, 2011).

1.13.3 Carmichael, Mississippi

In its report of a pipeline rupture, liquid propane release, and fire near Carmichael, Mississippi, on November 1, 2007,⁹⁴ the NTSB noted that although an operator's PAP plan may meet API RP 1162 requirements and Federal pipeline standards, compliance is not a guarantee that implementation is effective or that the operator is exercising adequate oversight. The NTSB made the following recommendation to PHMSA:

Initiate a program to evaluate pipeline operators' public education programs, including pipeline operators' self-evaluations of the effectiveness of their public education programs. Provide the National Transportation Safety Board with a timeline for implementation and completion of this evaluation. (P-09-3)

In response to this recommendation, PHMSA expanded its state and Federal inspection programs to include a review of operators' effectiveness evaluations, and developed detailed inspection guidance for pipeline safety inspectors. These inspections are currently ongoing and focus on how operators evaluate their PAPs for effectiveness, the results of the evaluations, how the results were documented, and what improvements were identified and implemented. The NTSB classified this safety recommendation "Closed—Acceptable Action."

1.14 Postaccident Actions

1.14.1 PHMSA Corrective Action Order

On July 28, 2010, PHMSA issued a corrective action order (CAO) requiring Enbridge to ensure the safety of Line 6B before authorizing its return to service. The CAO required Enbridge to submit a return to service plan, including procedures for repairs and monitoring the pipeline if service were resumed. It also required Enbridge to submit an integrity verification plan that includes a comprehensive review of the operating history of Line 6B, further inspections, testing, and repairs within and beyond the immediate rupture area.

On August 9, 2010, Enbridge submitted its response to the CAO and its proposed restart plan. On August 10, 2010, after reviewing the response and the restart plan, PHMSA stated that "(the plan) does not contain sufficient technical details or adequate steps to permit a conclusion that no immediate threats are present elsewhere on the line that require repair prior to any restart of a pipeline, even at a further reduced pressure." PHMSA refused to approve any Enbridge restart plan that did not include a minimum of four investigative excavations and a hydrostatic pressure test. Enbridge completed the investigative excavations and successfully pressure tested a portion of Line 6B that included the rupture site on August 30, 2010. After reviewing the Enbridge integrity verification results and the proposed restart plan, PHMSA issued an amendment to the CAO on September 17, 2010, establishing expectations for repair of known defects and the collection of additional integrity data. Enbridge revised its restart plan again and resubmitted it on September 21. PHMSA approved the revised restart plan 2 days later on

⁹⁴ *Rupture of Hazardous Liquid Pipeline With Release and Ignition of Propane, Carmichael, Mississippi, November 1, 2007*, Pipeline Accident Report NTSB/PAR-09/01 (Washington, D.C.: National Transportation Safety Board, 2009).

September 22 and authorized a staged restart of Line 6B at a reduced MOP, beginning September 27, 2010.

1.14.2 PHMSA's Notice of Probable Violation

On July 2, 2012, PHMSA issued a Notice of Probable Violation (NOPV) to Enbridge citing 24 violations and a total preliminary civil penalty of nearly \$3.7 million. Enbridge is required to respond to the NOPV within 30 days of receipt. The violations contained in the NOPV include the following:

- Four violations of 49 CFR 195.452 (integrity management rule) including discovery of condition, risk analysis related to pipeline segments in an HCA, and the integration of all threats during integrity assessments of the pipeline.
- Three violations of 49 CFR 195.401 related to the failure to stop the pipeline when the Edmonton control center received the alarms during the shutdown and the two startups that were indicative of a condition affecting safe operation.
- Eleven violations of 49 CFR 195.402 related to the failure of the Edmonton control center to follow established procedures during the shutdown and startup of Line 6B.
- One violation of 49 CFR 195.440 related to the Enbridge public awareness program effectiveness.
- Two violations of 49 CFR 195.52 related to the timeliness and accuracy of information in the early notifications made by Enbridge to the NRC.
- Two violations of 49 CFR 195.54 related to the timeliness and accuracy of information submitted to the DOT.
- One violation of 49 CFR 195.505 related to the operation of Line 6B by operator A1, an unqualified individual. (Operator A1 was a trainee who had just returned after being on sick leave for 6 months).

1.14.3 Enbridge Actions

1.14.3.1 Line 6B Replacement Projects

Since the Marshall accident, Enbridge has announced two replacement projects, identified as phase 1⁹⁵ and phase 2,⁹⁶ that combined will replace the entire 285 miles of Line 6B in the United States. The phase 1 replacement project, announced in May 2011, replaces 75 miles of noncontiguous segments of Line 6B located in Michigan and Indiana. Enbridge expects to complete phase 1 by 2013.

⁹⁵ Enbridge Phase 1 Line 6B Replacement Project, State of Michigan, The Michigan Public Service Commission Case No. U-16856 (August 26, 2011) and U-16838 (August 12, 2011).

⁹⁶ Enbridge Phase 2 Line 6B Replacement Project, State of Michigan, The Michigan Public Service Commission; Case No. U17020.

The application for phase 2 of the Line 6B replacement was filed on Monday, April 16, 2012, with the Michigan Public Service Commission to replace another 160 miles of Line 6B in Michigan and 60 miles of Line 6B in Indiana. The phase 2 request included increasing the diameter of 110 miles of existing 30-inch-diameter pipeline to 36-inch-diameter pipeline between Griffith and Stockbridge to boost the capacity of the line. The remaining 50 miles of pipe would be replaced with 30-inch-diameter pipe between Ortonville and the St. Clair River in Marysville, Michigan.

In the 2012 filing to the Michigan Public Service Commission, Enbridge stated the following:

Enbridge's decision to replace these segments minimizes the amount and frequency of future maintenance activities. While ongoing integrity inspections, testing and maintenance achieve required safety standards, replacement for the remaining Line 6B segments is the more cost-effective option to meet the current and future capacity requirements of its shippers.

1.14.3.2 Enbridge Operator Training

Following the Marshall accident, Enbridge increased the number of emergency response simulator sessions that operators took from one per year to two per year. Students also participated in two additional training sessions annually: one on human factors, which included fatigue, and one on hydraulics. The additional human factors training was administered in response to PHMSA's new rules addressing control center management.

1.14.3.3 Integrity Management

Enbridge issued new procedures following the accident in the areas of integrity management and control center operations. Enbridge now requires engineering assessments of cracks to use the smaller of either the nominal wall thickness or the prior measured wall thickness from in-line inspections. Enbridge also adopted a method of analyzing SCC features independently of fatigue by examining the strain rate of the crack. Pipeline excavation and inspection criteria have also been changed so that inspection features identified as crack-field are excavated if the longest indication measures 2.5 inches. Enbridge now includes the tool error, derived from excavation data, in the calculations of failure pressure and fatigue life and inspects overlays to examine overlap between corrosion and cracking. Enbridge also has implemented an excavation program that ensures a statistically significant number of excavations will occur, which establishes a confidence interval based on the tool's results and verifies that the tool bias numbers are reliable.

1.14.3.4 Enbridge Control Center

Enbridge added two technical specialists, who have previous control center experience, to the control center to assist operators when required. Before the Marshall accident, Enbridge had planned to move its control center to a new location. The new center was completed in December 2011, and its control center operations moved to the center at that time.

Oversight of the control center was transferred from the vice president, customer service to senior vice president, operations. A new vice president, pipeline control and a new director, control center were selected. The control center operations were divided into a terminal side and a pipeline side with technical specialists added to each. The specialists support the shift lead and the operator in technical issues. The three operators and the two shift leads involved in the accident were temporarily reassigned to positions outside of the control center. The two shift A operators retired from the company: one in September 2011 and the other in November 2011.

All operators, shift leads, and MBS analysts were provided additional technical training on hydraulics, control center roles and responsibilities, procedure compliance, column separation analysis, and the 10-minute operational limit. MBS analysts were required to note to shift leads, operators, and on-call supervisors, in response to an MBS alarm, only whether the alarm was valid or not. Operators were annually given an additional simulated emergency scenario and human factors training on fatigue (a PHMSA requirement that was independent of this accident) and on lessons learned from previous accidents. Procedures governing the documentation of information to be communicated during shift changes were developed and implemented.

Enbridge reemphasized the rule that requires an operator to shut down a line after 10 minutes if a problem remains unresolved. Operators and supervisors were prohibited from overriding approved control-room procedures. On-call procedures were revised to make available additional personnel—including the control center director and the senior vice president—when control center staff needed assistance. These on-call individuals were given (1) specific procedures to follow and (2) questions to be asked in particular circumstances.

Enbridge has also stated that additional flow meters have been installed on Line 6B increasing the number of segments that are calculated within the MBS system and increasing its accuracy.

1.15 Federal Oversight

1.15.1 Canadian and U.S. Regulation

Enbridge operates pipelines in both Canada and the United States from its Edmonton, Alberta, Canada, operations center. Hazardous liquid pipelines in the United States are subject to U.S. oversight by PHMSA, and those in Canada are subject to Canadian oversight by the NEB. Pipelines that originated in Canada and terminated in the United States were subject to the requirements of both PHMSA and the NEB. PHMSA and NEB currently operate under a memorandum of understanding signed in 2005 that outlines when notifications are to be made between agencies with respect to enforcement and inspections.

According to Enbridge's manager, United States/Canadian compliance, Enbridge did not find conflicts in meeting the requirements of the two regulators. Rather, where reporting requirements of the two regulators were different, the company either met the requirements of the applicable regulator or those of the regulator with more rigorous standards.

1.15.2 Enbridge 2010 Long-Term Pressure Reduction Notification

On July 15, 2010, Enbridge filed a notification with PHMSA regarding pressure restrictions on Line 6B that would exceed the 365 days allowed under 49 CFR 195.452(h)(1)(ii).⁹⁷ Beginning in February 2004, Enbridge had PII conduct an in-line corrosion inspection of Line 6B, from the Griffith PS to the Sarnia Terminal. The inspection was performed using an ultrasonic USWM tool and the results showed some areas with echo-loss readings near pitting corrosion.⁹⁸ To ascertain the depth in these areas of echo loss, a second inspection was conducted on October 13, 2007, using an MFL in-line inspection technology that was not subject to echo-loss. Enbridge originally requested that the 2007 data be overlaid with the 2004 inspection data.

In July 2008, because of difficulties in trying to overlay the two sets of data from the 2004 and 2007 inspections, Enbridge instructed PII to treat the more recent in-line inspection (2007 MFL) as a standalone report. PII issued its initial standalone report in November 2008. This initial report contained an equipment error⁹⁹ that affected the sizing and the location of some features in the pipeline. PII issued a revised report in May 2009 that corrected the errors in feature sizing. However, the errors had occurred more than halfway along Line 6B; therefore, the data collected in the first half of the inspection was unaffected.

By July 17, 2009, Enbridge identified 114 corrosion features (downstream of the ruptured segment) from the 2007 inspection that required self-imposed pressure restrictions to maintain the pipeline integrity. Under the regulations, a pipeline operator may impose pressure restrictions on its pipeline as a temporary remediation measure to integrity defects for up to 365 days.

In its filing to PHMSA in 2010, Enbridge referred to the July 17, 2009, date as the “discovery of condition” date. Under 49 CFR 195.452 (h)(2)¹⁰⁰ a “discovery of condition” must be made within 180 days following an integrity assessment; Enbridge noted that the 180 days expired on April 10, 2008. Enbridge’s July 17, 2009, “discovery of condition” date was 463 days past the 180 days allowed under the regulations and 643 days past the date that the in-line inspection was originally conducted.

1.15.3 PHMSA Inspections

PHMSA regulates the transportation of hazardous liquids and gases by pipeline in the United States. PHMSA conducted an Integrity Management Segment Identification and Completeness Check of Enbridge’s integrity management program from February 26 to 27, 2002. The

⁹⁷ Title 49 CFR 195.452(h)(1)(ii), Long term pressure reduction, states that “When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.”

⁹⁸ Pitting corrosion is a form of localized corrosion that generates small holes in the external surface of the pipe.

⁹⁹ This was reported as an error due to slippage of the odometer wheel installed on the tool, which is responsible for recording the start and end of the defect when detected by the sensors.

¹⁰⁰ Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

audit found deficiencies in the process Enbridge was using to identify segments that could affect HCAs. PHMSA issued a notice of amendment to Enbridge on May 15, 2002. In its final response, dated September 3, 2002, Enbridge agreed to modify its segment identification plan.

From May 12 to June 2, 2003, PHMSA inspected Enbridge's integrity management plan. After the inspection on December 21, PHMSA issued a NOPV, Warning Letter, Notice of Amendment, and Letter of Concern, identifying 14 separate issues that included 3 probable violations, 5 procedural issues, and 6 areas of concerns. The 3 probable violations were changed to "Warning Letter" by PHMSA because no civil penalty or compliance order was proposed. One violation involved the Plummer to the Clearbrook pipeline section of Line 4. The discovery of several anomalies was made within 180 days of completion of in-line inspection of the pipeline, but these anomalies were erroneously classified as "previously repaired" and were excluded from the remediation plan. In another violation, PHMSA stated,

Enbridge's information analysis procedures did not adequately consider data from other inspections and tests. Also, the process of evaluation of each pipeline segment by analyzing all available data was insufficient to gain a complete understanding of pipeline integrity (195.452(f)(3)(g)(3)).

Enbridge responded on January 28, 2005. Enbridge's response stated that for all hazards (external corrosion, internal corrosion, SCC, weld cracking, mechanical damage), specific defect analysis is conducted. Based on Enbridge's response, PHMSA ultimately closed the file on March 20, 2007. PHMSA conducted a second comprehensive integrity management program review of Enbridge during the weeks of June 12 and June 26, 2006. The detailed protocol inspection format was utilized to review Enbridge's processes for the following:

- Integrating information from all relevant sources to understand location-specific risks for these segments...
- Identifying and implementing remedial actions for anomalies and defects identified during integrity assessments...
- Performing periodic evaluations and on-going assessments of pipeline integrity; and
- Evaluating Integrity Management performance.

A summary report was prepared by PHMSA at the conclusion of the inspection identifying 13 recommendations concerning Enbridge's integrity management plan. Concerning a continual process of evaluation and assessment, PHMSA noted during the inspection that

The lack of a periodic evaluation process was indicative of the Enbridge approach to integrity management, where the pigging/[pipeline integrity management] activities are largely done separate from risk assessment activities. Utilization of available information/risk analysis information appears to be limited to the evaluation of certain additional [preventive and maintenance] measures and is not well integrated with key integrity/assessment decisions. In effect, Enbridge

[integrity management]-related groups operate semi-independently, and it is not clear that overall integration of knowledge and data is occurring on a consistent basis.

1.15.4 Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

On January 3, 2012, pipeline safety legislation was signed into law by the President, Public Law 112-90. The new law contains provisions related to public awareness, response plans, leak detection, and the transportation of diluted bitumen.

Under section 6(a) of the law, PHMSA has 1 year to do the following:

...develop and implement a program promoting greater awareness of the existence of the National Pipeline Mapping System to State and local emergency responders and other interested parties. The program shall include guidance on how to use the National Pipeline Mapping System to locate pipelines in communities and local jurisdictions.

Section 8(a) of the statute also requires that PHMSA make the response plans filed by pipeline operators available to the public upon written request.

This law also addresses leak detection systems of pipeline operators and requires that PHMSA study the “technical limitations” of current systems and how to foster the development of better technologies and incorporate the requirements of these systems into the Federal code if feasible. PHMSA is also required to perform a study of the transportation of diluted bitumen to determine whether the existing regulations are sufficient to protect pipelines that transport these products. Line 6B transports diluted bitumen crude oil extracted from the Alberta oil sands.

1.15.5 National Energy Board

The NEB is an independent regulatory agency of the Government of Canada charged with overseeing international and interprovincial aspects of the oil, gas, and electric utility industries. Based in Calgary, Alberta, Canada, the NEB regulates the construction and operation of oil and natural gas pipelines crossing provincial or international borders. Because segments of the pipeline infrastructure in Canada and the United States are interconnected, PHMSA and the NEB entered into an agreement on November 22, 2005, to improve pipeline safety and enhance cooperation.¹⁰¹ The NEB completed an inspection of Enbridge on July 18, 2008; it identified the following issues.

The NEB stated that because Enbridge’s integrity management program encompassed multiple departments (for example, integrity management, engineering, and risk management) with interconnected areas of responsibility, Enbridge should create a structured management program and implement a formal documentation process across the organization.

¹⁰¹ Because Enbridge’s pipelines extend into the United States, they are subject to PHMSA’s regulations.

The NEB further stated that Enbridge's integrity management program needed a hazard and threat identification assessment process that considers fatigue-dependent cracking, among other threats. The NEB noted the following:

The assessment process and data for determining the crack and corrosion in-line inspection frequency required improvement to prevent failures from reoccurring. Ongoing evaluation of the effectiveness of the crack management plan is required such that [in-line inspection] frequency can be reliable. a) [In-line inspection] Accuracy of crack detection and sizing; b) Validity of Crack Growth Modeling in regards to input data (i.e. material properties and growth coefficients) and ongoing field verification of assumptions; and c) Determination of the crack—susceptible pipelines accounting for the level of identified data uncertainty (i.e. unknown and non-reliable input data) and continuous validation by field investigation.

Similar to PHMSA's findings, the NEB also noted that Enbridge's departments were not well integrated, particularly when performing risk assessments. The NEB found that:

Validation of the corrosion assessment interval results and the evaluation of their influence in the external corrosion mitigation and monitoring programs are required. Similarly, validation of crack detection [in-line inspection] performance, crack growth modeling, re-inspection frequency, susceptibility to cracking of Enbridge's pipeline segments, and the evaluation of their influence in the crack mitigation and monitoring programs are also required.

During its inspection, the NEB discovered that each of Enbridge's departments was independently assessing coincidental features. The NEB stated that for Enbridge's integrity management program to be effective—that is, to identify, monitor, assess, and mitigate threats—all departments should be participating in an integrated integrity management process. Enbridge submitted its corrective action plan to the NEB on February 2, 2009.

1.15.6 PHMSA Inspection of Enbridge's PAP

In May 2011, Enbridge revised its PAP and created a public awareness committee that includes a performance metrics subcommittee. According to the committee charter, the committee will meet four times a year and will be responsible for the annual review of the PAP and the program performance measures.

In July 2011, PHMSA conducted an inspection of Enbridge's May 2011 PAP. PHMSA's inspection report noted the following two findings:

Enbridge's PAP does not have a written implementation review process that clearly identifies both supplemental and overall PAP implementation.

Enbridge does not have a process in the PAP that outlines a consistent format and methodology for evaluating program outreach, understandability of message content, desired stakeholder behavior, and bottom-line results.

1.15.7 PHMSA Facility Response Plan Review and Approval

PHMSA had reviewed and approved Enbridge's facility response plan before the accident. The EPA consulted the plan during the initial phase of the response to the Marshall accident to gain an understanding of Enbridge's response resources and planning. The EPA noted that the plan did not have information specific to spill response at any particular location. As of the date of this report, PHMSA has not performed a postaccident review of the facility response plan. PHMSA told NTSB investigators that it will review the lessons learned from the Marshall accident either when Enbridge renews its facility response plan in 2015 or when Enbridge amends its facility response plan, whichever Enbridge completes first.

PHMSA's plan review process was supposed to emphasize the adequacy of the pipeline operator's response resources, incident command system, and ability to protect environmentally sensitive areas. PHMSA's environmental planning officer told NTSB investigators that these plans are assessed based on the reviewer's professional experience and judgment.

PHMSA also required plan holders to respond to a 16-element self-assessment questionnaire. On April 1, 2010, Enbridge submitted its responses and affirmed the adequacy of the following elements:

- Whether the facility response plan identifies enough spill containment equipment and recovery capacity to respond to a worst-case discharge to the maximum extent practicable;
- If the facility response plan identifies spill recovery strategies appropriate for the response zones;
- If planned spill recovery activities can be accomplished within the appropriate tier times;
- Whether the plan identifies enough trained personnel to respond to a worst-case discharge.

PHMSA's environmental planning officer reviewed the facility response plan and questionnaire without requesting supplemental information. On April 15, 2010, the environmental planning officer notified Enbridge that its facility response plan had been approved. PHMSA's correspondence to Enbridge did not cite any deficiencies in the plan.

Following the Marshall accident, PHMSA asked the DOT Volpe National Transportation Systems Center (Volpe) to identify the processes used by four Federal agencies responsible for reviewing facility plans that are required under the Oil Pollution Act of 1990. According to Volpe's draft report, at the time of the accident, PHMSA had 1.5 employees to oversee about 450 facility response plans. Until June 2010, one PHMSA environmental planning officer reviewed and approved facility response plans.

Currently, authority to review and approve facility response plans is assigned to a division director. PHMSA reported that another full-time employee has been assigned to oversee spill response plans since the data were collected for Volpe's draft report. In contrast, Volpe's draft report stated that EPA Region 6 had 2 employees, 3 contractors, and 22 on-scene

coordinators¹⁰² to review 1,700 facility response plans. The Coast Guard Sector Boston oversees 45 facility response plans with a staff of 4 inspectors and 3 to 4 trainees.

Volpe’s draft report stated that PHMSA does not perform on-site audits or unannounced drills for operators who submit facility response plans for approval. Both the Coast Guard and the EPA conduct on-site audits and plan reviews after initial review and approval of the submitted plan. In addition, both the Coast Guard and the EPA conduct announced and unannounced exercises to test the effectiveness of plans. Although the Coast Guard and the EPA report to their headquarters offices on the number of plans, noncompliances, and inspections conducted, PHMSA has not currently implemented performance metrics for its facility response plan program. Table 6 provides key findings of the Volpe draft report, contrasting PHMSA’s plan review process with those of the other Federal agencies that are responsible for response plan review.

Table 6. Volpe’s comparative study of response plan review.

| | PHMSA | EPA | Coast Guard |
|--|-------|--|---|
| Centralized collection of plans | Yes | No | Yes vessel response plan |
| Regional collection of plans | No | Yes | Yes |
| Information system support | No | Yes | Yes |
| Number of plans | 450 | 500 for Region 5 1,500 for Region 6 | 3,000 vessel response plans and hundreds of facility response plans (fixed and mobile) |
| Number of staff involved in plan review | 1.5 | 35 in Region 5 5 in Region 6 | 21 in headquarters (18 for vessel response plan; 3 for facility response plan) and hundreds in the field |
| Completeness review conducted ^a | Yes | Yes | Yes |
| Second level review conducted ^b | No | Yes | Yes |
| Unannounced or announced drills or exercises to verify plans | No | Yes | Yes |

^a Completeness review involves the staff member using a checklist to ensure all required elements of the plan are present.

^b A second level review is conducted by a more senior level staff member prior to submitting a recommendation for approval to the approving authority.

¹⁰² The on-scene coordinator can be delegated to authorize plans as needed based upon workload.

PHMSA's director of emergency support and security reported that in its 2012 budget request, PHMSA requested eight additional personnel and over \$1 million to enhance its field oil-related activities. However, those resources were not approved in the final budget. He reported that PHMSA is developing plans to increase oil-related activities in its field program.

1.15.8 PHMSA Facility Response Plan Advisory Bulletin

On June 23, 2010, PHMSA issued Advisory Bulletin PHMSA-2010-0175, in light of the Deepwater Horizon oil spill in the Gulf of Mexico,¹⁰³ advising pipeline facility response plan holders to review and update their plans within 30 days to ensure that adequate resources were available to comply with emergency response requirements to address a worst-case discharge. The bulletin noted that the response to the Deepwater Horizon spill had resulted in the relocation of oil spill response resources. The Enbridge senior emergency response engineer responded to the advisory bulletin on July 21, 2010, by stating that Enbridge had assessed its emergency preparedness in relation to a worst-case discharge for each of its response zones. He reported that two oil spill response organizations—Bay West and Garner Environmental Services, Inc.—have confirmed their ability to deploy appropriate spill response resources in the response zones. He further responded:

In relation to the Advisory Bulletin, we have reassessed our facility response plan and concluded that our plan is complete, complies with 49 CFR Part 194, and is appropriate for responding to a worst case discharge in our Chicago Region Response Zone.

1.15.9 Response Preparedness

The National Preparedness for Response Exercise Program (PREP), a unified Federal effort to satisfy the exercise requirements of the Coast Guard, the EPA, PHMSA, and the U.S. Department of the Interior's Minerals Management Service,¹⁰⁴ was developed to establish a spill response exercise program in accordance with the Oil Pollution Act of 1990. PREP became effective on January 1, 1994. PHMSA requires an operator to satisfy the requirement for a drill program by following the *PREP Guidelines*. PREP requirements for onshore transportation-related pipelines require facility response plan holders to participate in both internal (facility-specific) and external (area-specific) exercises.

Section 5 of the *PREP Guidelines* provides for unannounced government-initiated exercises to test plan holder's ability to respond to a worst-case discharge event. These full-scale exercises, which are used to evaluate a plan holder's operational capability, involve all levels of the organization and all aspects of a response operation. Plan holders are not required to

¹⁰³ Deepwater Horizon was an ultra-deepwater semi-submersible offshore oil drilling rig located in the Gulf of Mexico about 250 miles southeast of Houston, Texas. On April 20, 2010, while drilling, an explosion on the rig killed 11 crewmembers and ignited a fire. By April 22, the rig sank, leaving the well gushing oil at the seabed, resulting in the largest offshore oil spill in U.S. history, with an estimated release of 172.2 to 205.8 million gallons of crude oil.

¹⁰⁴ On October 1, 2011, the Minerals Management Service was succeeded by the Bureau of Safety and Environmental Enforcement.

participate in unannounced exercises if they have already participated in one during the previous 36 months. Although PHMSA recently has not been conducting unannounced government-initiated exercises, it has committed to conducting not more than 20 per year on the regulated pipeline industry. Records indicate that since 2005, PHMSA has participated in only one exercise per year and has not hosted any exercises specific to pipeline facilities.

The *PREP Guidelines* identify 16 facility response plan core components that should be exercised at least once during each triennial cycle. These core components relate to areas such as notifications, mobilization of resources, response management, and the ability to contain and recover a discharge. According to the *PREP Guidelines*, PHMSA is responsible for verifying internal exercises and for conducting and certifying external exercises conducted by the operator and other Federal agencies.

During the 10-year period from 2002 to 2011, PHMSA participated in 26 drills and exercises. Enbridge participated in the September 24, 2003, exercise in Sault Ste. Marie, Michigan, which was led by the Coast Guard and PHMSA, and in the March 10-11, 2004, exercise in Cushing, Oklahoma, led by the Federal Bureau of Investigation, PHMSA, and more than 20 Federal, state, and local government agencies. PHMSA's environmental planning officer told NTSB investigators that Enbridge successfully completed both exercises. Key Enbridge personnel who participated as initial responders to the Marshall accident reported that they have continued to receive annual boat-handling and oil-boom deployment training for creeks and rivers. Several responders had previous experience with much smaller oil spills. None of the Enbridge first responders reported having had experience responding to an oil spill of this magnitude or having had previous training for oil spills in high water and swift moving creeks. The Enbridge response personnel also told NTSB investigators that they had no experience constructing underflow dam oil-containment structures, although some were aware of the technique.

1.15.10 PHMSA Control Center Management

PHMSA promulgated the control center management rule in 2009 in response to recommendations generated as part of the NTSB 2005 SCADA study and to fulfill the requirements of the PIPES Act of 2006, Public Law 109-468, which was enacted on December 29, 2006. Section 12(a) of the statute, concerning pipeline control center management, required the U.S. Secretary of Transportation to do the following:

- (a) Issue regulations requiring each operator of a gas or hazardous liquid pipeline to develop, implement, and submit to the Secretary...a human factors management plan designed to reduce risks associated with human factors, including fatigue, in each control center for the pipeline. Each plan must include, among the measures to reduce such risks, a maximum limit on the hours of service established by the operator for individuals employed as controllers in a control center for the pipeline.

Further, section 19 of the act, "Standards," called on the Secretary of Transportation, no later than June 1, 2008, to implement actions corresponding to those called for in Safety Recommendations P-05-1, -2, and -5.

Require operators of hazardous liquid pipelines to follow the American Petroleum Institute's Recommended Practice 1165 for the use of graphics on the Supervisory Control and Data Acquisition screens. (P-05-1)

Require pipeline companies to have a policy for the review/audit of alarms. (P-05-2)

Require operators to install computer-based leak detection systems on all lines unless engineering analysis determines that such a system is not necessary. (P-05-5)

PHMSA modified existing gas and liquid pipeline regulations contained in 49 CFR 192 and 195 to address the requirements of P-05-1 and -2 and both recommendations were classified "Closed—Acceptable Action" on April 28, 2010. PHMSA's rule modifications, which took effect on February 1, 2011, were similar for liquid and gas pipelines and required pipeline operators to comply with the requirements by August 1, 2011. The modified regulations pertaining to liquid pipelines were incorporated into 49 CFR 195.446, "Control Room Management."

Safety Recommendation P-05-5 was classified "Closed—Acceptable Alternate Action" on May 6, 2010, based on PHMSA's integrity management requirements to detect and repair leaks through defect repair prioritization, risk based assessment, repair prioritization of defects by environmental consequence, corrosion management, right-of-way surveillance, public awareness leading to citizen identifications of leaks, emergency preparedness and lessons learned from accident analysis. In addition, PHMSA issued Advisory Bulletin ADB-10-01 informing pipeline operating companies of PHMSA's expectations regarding pipeline leak detection systems. Operators must justify the reasons for not having a leak detection system, and if leak detection systems are not in place, operators must perform hourly balances by hand.

According to PHMSA's Central Region supervisor of accident investigations, its representatives met with DOT personnel involved in overseeing aviation and rail operations, the Coast Guard, and the Nuclear Regulatory Commission between 2004 and 2007, which was before PHMSA developed control room management rules. These meetings were conducted to learn about the best practices in the oversight by Federal regulators from the perspective of the regulators. The meetings also included the Federal Aviation Administration's (FAA) Civil Aerospace Medical Institute to review human factors oversight issues. This was done to assist PHMSA in the development of its new control room regulations.

In addition to its regulations, PHMSA issued several advisory bulletins governing control rooms and SCADA systems. Advisory Bulletin 04-05, issued on November 26, 2006, explained the parts of 49 CFR 192 and 195 that required gas and liquid pipeline operating companies to establish and maintain operator qualification programs. The advisory bulletin advised pipeline operating companies to include periodic requalification for operators at intervals that "reflect the relevant factors including the complexity, criticality, and frequency of the performance of the task."

Advisory Bulletin 05-06 responded to NTSB Safety Recommendation P-98-30, which called upon PHMSA’s predecessor agency to “assess the potential safety risks associated with rotating pipeline controller shifts and establish industry guidelines for the development and implementation of pipeline controller work schedules that reduce the likelihood of accidents attributable to controller fatigue.”

1.16 Other Information

1.16.1 Oil Spill Response Methods

Effective oil spill removal strategies largely depend on the crude oil mixture’s density and its tendency to float or sink in fresh water. Once the crude oil mixture (oil and diluents) enters the environment, weather factors, volatility, and physical agitation affect the composition, thus allowing some of the oil to sink into river sediments and collect on the river bottom.

The most effective response methods to control the environmental consequences of an oil spill vary according to the specific spill conditions (that is, the type and amount of oil, weather and site conditions, and the effectiveness of the response strategies). The time required to bring needed resources and personnel to the scene is also critical to an effective response. Response actions are most viable and effective very early during a response. When the oil is concentrated near the discharge source, focusing on source control, containment, and removal near the source provides the best opportunity to reduce adverse environmental impact.¹⁰⁵

Although Talmadge Creek flow data were not available for the day of the accident, Enbridge first responders told NTSB investigators that the water flow was faster than they had previously seen. Coast Guard research indicates that controlling and recovering oil spills in fast moving water (above 1 knot) is difficult because oil flows under booms and skimmers in swift current, thus necessitating quicker and more efficient responses.¹⁰⁶ In a stream with a flow rate greater than 10 cubic feet per second, the Coast Guard recommends the use of underflow dams, overflow dams, sorbent barriers, or a combination of these techniques instead of deploying oil containment boom.

Underflow dams can be erected in shallow rivers and culverts using hand tools or heavy machinery. Pipes are used to form an underflow dam, which allows water to pass, while retaining oil. On the day the release was discovered, Enbridge first responders used surplus pipe and an excavator at the Marshall PLM shop to construct an earthen underflow dam. Underflow dams also can be installed quickly at culverts by using sheets of plywood or another suitable barrier to prevent floating oil from escaping downstream.

On July 26, Enbridge responders installed skirted oil boom and sorbent boom across the corrugated pipe culvert under Division Drive. (See figure 21.) When asked to identify lessons

¹⁰⁵ *Characteristics of Response Strategies: A Guide for Spill Response Planning in Marine Environments* (American Petroleum Institute, National Oceanic and Atmospheric Administration, U.S. Coast Guard, and U.S. Environmental Protection Agency joint publication, June 2010).

¹⁰⁶ *Oil Spill Response in Fast Moving Currents, a Field Guide* (Groton, Connecticut: U.S. Coast Guard Research and Development Center, October 2001).

learned from the response, the Bay City PLM supervisor told NTSB investigators that, in the future, he would ensure that sheets of plywood are included in Enbridge's boom trailers so that adjustable underflow dams can be constructed over culvert pipes.

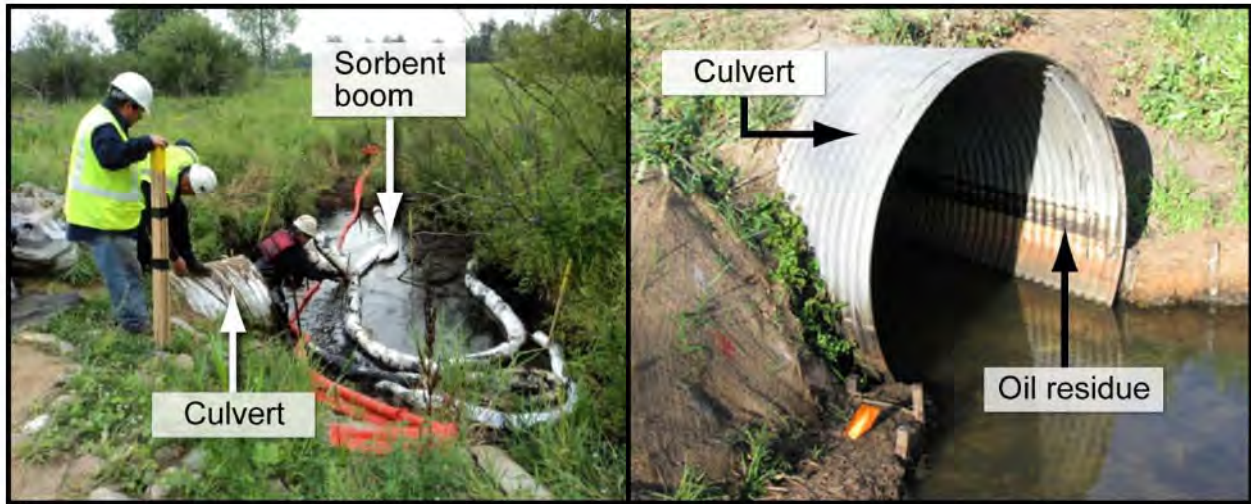


Figure 21. (Left) Enbridge employees install sorbent boom in front of a culvert at Division Drive. (Right) Oil residue marks the level of the oil carried through this culvert following the Enbridge release from Line 6B.

The EPA's Region 5 Integrated Contingency Plan discusses response methods for small river and stream environments, in which the primary use of booming should be to divert slicks toward collection points in low-current areas. The plan states that booming is ineffective in fast shallow water and in steep bank environments. The plan also states that sorbent boom should be used to recover sheen in low current areas and along the shore. Although sorbent boom effectively absorbs oil sheen in stagnant water, it is an ineffective barrier to flowing oil.¹⁰⁷

The Coast Guard's Research and Development Center further describes the proper use of sorbent boom, stating that it is used to recover trace amounts of oil and sheen in stagnant or slow moving water, or as a polishing technique to control escaping sheen from containment boom. The Coast Guard recommends that when containment boom is used in a fast moving current, the maximum deflection angle must be maintained to channel the oil toward calm water along the bank.

The Enbridge operating and maintenance procedure for emergency response identifies methods for containing oil in wetlands, rivers, and sensitive areas. The procedure states that when containing releases in rivers, an attempt must be made to confine the product as close to the source as possible to prevent the product from entering a major river. The procedure states that releases could be contained using one or a number of the following techniques: containment booms, diversion booms, sorbent booms, earth dikes, and containment weirs. The procedure for containing releases in rivers stated that sorbent booms may be used in calm waters when current speeds are less than 1.64 feet per second and the degree of contamination is minor.

¹⁰⁷ *Mechanical Protection Guidelines* (Research Planning, Inc., National Oceanic and Atmospheric Administration, and U.S. Coast Guard National Strike Force joint publication, June 1994).

1.16.2 API Standard 1160—Managing System Integrity for Hazardous Liquid Pipelines

The API Standard 1160, *Managing System Integrity for Hazardous Liquid Pipelines*, stresses that regulation should be used as the foundation of a high-quality integrity management program, rather than relying solely on a compliance approach. Some of the standard’s “Guiding Principles” include the following:

- An integrity management program must be flexible. The program should be customized, continually evaluated, and modified as appropriate to accommodate changes in the pipeline system.
- The integration of information is a key component for managing system integrity. It is important to integrate all available information from various sources in the decision-making process.
- Identifying risks to pipeline integrity is a continuous process. Analyzing for risks in a pipeline system is a continuous reassessment process. The operator will periodically gather additional information and system operating experience. This information should be factored into understanding system risks.

The standard states that all “coincident occurrence” of suspected high-risk conditions or events should be compared using existing data. The standard further stresses that data should be timely, complete, and of high quality.

2 Analysis

2.1 Introduction

This analysis explains the probable cause of the accident and includes a discussion of the following safety issues identified in this report:

- Multiple aspects of Enbridge's organization, including pipeline integrity management, operations control room management, leak detection and recognition, public awareness, and environmental response.
- PHMSA's oversight of pipeline operating companies' SCADA systems, integrity management programs, and facility response plans.
- Federal pipeline safety regulations governing the assessment and repair of crack defects under operators' integrity management programs.

The remainder of this introductory section discusses those elements of the investigation the NTSB determined were not factors in the accident.

The ruptured segment of Line 6B had a polyethylene tape coating and a cathodic protection system, which was operating in excess of the minimum levels specified in the regulations, to mitigate external corrosion. The coating had disbonded, and the NTSB Materials Laboratory's examination revealed large areas of general corrosion and pitting at and near the pipe's longitudinal seam weld in the disbonded areas. Because Line 6B's polyethylene tape coating had disbonded, the surface of the pipe was exposed to the surrounding environment and susceptible to corrosion. However, the pattern and location of the disbondment were not consistent with degradation associated with cathodic protection systems. Therefore, the operation of the cathodic protection system was not considered a factor in this accident.

To investigate any potential microbial contribution to the corrosion, the EPA and the NTSB conducted microbial testing. The EPA's results from liquid samples showed higher microbial concentrations than the NTSB's results from surface samples. Knowing the microbial concentrations on the metal surface is critical to estimating microbial contributions to corrosion damage; therefore, the NTSB conducted microbial tests using corrosion product and deposit samples obtained from the pipe's surface beneath the coating. The results showed the presence of low concentrations of microorganisms in the samples; however, features typically associated with microbial corrosion were not observed on the corroded areas of the pipe. Therefore, microbial corrosion was not considered a factor in the rupture.

Enbridge had an internal corrosion management program since 1996 that used cleaning tools, biocide, and inhibitors to mitigate internal corrosion of its pipelines. The NTSB's examination of the ruptured pipe segment showed that the internal pipe surfaces were free from any apparent corrosion or other visible surface anomalies. Therefore, internal corrosion was not a factor in the rupture of Line 6B.

The NTSB's examination showed that the location of the fracture was inconsistent with transportation-induced metal fatigue or third-party damage. The fracture originated from corrosion pits on the external surface in the pipe's base metal and away from the longitudinal seam weld heat-affected zone. In addition, the NTSB's examination of the pipe showed no sign of third-party damage. Therefore, transportation-induced metal fatigue and third-party damage were not factors in the rupture.

The NTSB's testing of the chemical and mechanical properties of the steel taken from the ruptured segment showed the pipe met or exceeded the API specifications in place at the time the pipe was manufactured. Further, the rupture did not occur at the longitudinal seam weld or in the weld heat-affected zone, which are locations typically associated with manufacturing defects. In addition, no manufacturing anomalies were noted at the fracture origins. Therefore, pipe manufacturing defects did not contribute to the failure of the pipeline.

Based on the above information, the NTSB concludes that the following were not factors in this accident: cathodic protection, microbial corrosion, internal corrosion, transportation-induced metal fatigue, third-party damage, and pipe manufacturing defects.

2.2 Pipeline Failure

2.2.1 The Rupture

About 5:57 p.m. during the planned shutdown, the Line 6B operator increased the pressure at a pressure control valve near the Stockbridge Terminal to slow the flow rate in the pipeline and to increase the upstream pressure (toward the Marshall PS) by 150 psig. The pressure increase occurred in 16 seconds. About 45 seconds after the pressure had increased upstream of Stockbridge Terminal and just before the Marshall PS pump was stopped, Line 6B ruptured at a highest recorded pressure of 486 psig,¹⁰⁸ which was lower than the MOP of 624 psig and the pressure restriction of 523 psig. The pipeline segment ruptured due to corrosion fatigue cracks that had grown in size until the pipe failed during the planned shutdown. The corrosion fatigue cracks most likely grew from smaller cracks that were likely initiated by longitudinally oriented, near-neutral pH SCC from a corrosion pit. These cracks initiated from multiple origins along the 6-foot-8.25-inch rupture and in areas of external surface corrosion. The small cracks eventually grew in size and linked together to form one large crack. This segment of pipe was not excavated or repaired and the crack was allowed to grow to a depth of 0.213 inch relative to the original wall thickness of 0.254 inch (83.9 percent), and it resulted in a rupture coinciding with the pipeline shutdown operations on July 25, 2010.

2.2.2 Fracture Mechanism

The ruptured pipe segment was wrapped with polyethylene tape at the time of its installation in 1969. Since the late 1960s, coating technology has advanced significantly. The coatings available today follow the pipe's contour better and are more resistant to disbonding. Some of the newer coatings also allow cathodic protection to reach the pipe. Tape coating that is

¹⁰⁸ This discharge pressure was recorded locally at the Marshall PS.

well-adhered will remain tightly bonded to the external surface of a pipe; however, the tape coating on the ruptured segment had areas where the tape was loose and wrinkled with areas of localized bulging. Where the tape crossed the longitudinal seam weld, it was “tented” and the failure of the adhesive (that is, disbondment) was evident along multiple areas of the pipe, including areas away from the rupture location. Polyethylene tape-wrap coatings installed on pipelines with DSAW longitudinal seams are susceptible to disbondment due to tenting, particularly when the longitudinal seam weld is located at the 3 o’clock position on the pipe as it was in the ruptured segment.

The pipe had been installed through a wetland; the rupture occurred near the edge of the wetland, which potentially had subjected the ruptured segment to wet-and-dry environmental patterns. Moisture had penetrated areas where the coating was not adhered to the pipe. This disbondment exposed the pipe’s surface to conditions that are conducive to corrosion, near-neutral pH SCC, and corrosion fatigue. This observation was evident by the presence of corrosion and clusters of cracks along the length of the ruptured segment. The NTSB’s examination showed that fracture features emanated from the bottom of the individual corrosion pits at the external pipe surface. This observation indicated that the corrosion was in place prior to the crack formation and provided locations of concentrated stress for crack initiation.

The fracture features found on the ruptured segment were consistent with near-neutral pH SCC and corrosion fatigue as the fracture mechanism. When cross sections of the cracks were examined at a microscopic level, the cracks were observed extending through the metal grains with limited crack branching.¹⁰⁹ On the fracture surfaces, many fine crack-arrest lines were found near the origin areas of the cracks; farther away, larger broad-band crack-arrest features were found. These crack-arrest lines indicated areas of progressive advancement likely generated from either pressure cycles or changes in environmental conditions.

Near-neutral pH SCC and corrosion fatigue are forms of environmentally assisted cracking and share similar fracture features.¹¹⁰ However, the NTSB observed distinct differences in the crack arrest lines near the crack origins and those found farther away. These differences suggest a change in the fracture mechanism as the cracks propagated deeper into the pipe wall. Published experimental findings¹¹¹ show near-neutral pH SCC cracks that are about 0.020 inch

¹⁰⁹ Crack branching refers to crack growth where the crack path diverges into separate crack paths as it grows, appearing in cross section similar to the branches of a tree.

¹¹⁰ (a) J.I. Dickson and J.P. Bailon, “The Fractography of Environmentally Assisted Cracking,” in A.S. Krausz, ed., *Time Dependent Fracture: Proceedings of the Eleventh Canadian Fracture Conference, June 1984, Ottawa, Canada* (Dordrecht: M. Nijhoff Publishers, 1985). (b) G. Gabetta, “Transgranular Stress Corrosion Cracking of Low-Alloy Steels in Diluted Solutions,” *Corrosion*, vol. 53, no. 7 (1997), pp. 516–524.

¹¹¹ (a) W. Zheng and others, “Stress Corrosion Cracking of Oil and Gas Pipelines: New Insights on Crack Growth Behaviour Gained From Full-Scale and Small-Scale Tests,” 12th International Conference on Fracture 2009, July 12–17, 2009, Ottawa, Ontario, Canada. (b) B. Fang and others, “Transition from Pits to Cracks in Pipeline Steel in Near-Neutral pH Solution,” 12th International Conference on Fracture 2009, July 12–17, 2009, Ottawa, Ontario, Canada. (c) W. Chen and R.L. Sutherby, “Crack Growth Behavior of Pipeline Steel in Near-Neutral pH Soil Environments,” *Metallurgical and Materials Transactions A*, vol. 38, no. 6 (2007) pp. 1260–1268. (d) M.H. Marvasti, “Crack Growth Behavior of Pipeline Steels in Near Neutral pH Soil Environment,” master’s thesis, University of Alberta, 2010. (e) F. Song and others, *Development of a Commercial Model to Predict Stress Corrosion Cracking Growth Rates in Operating Pipelines*, SwRI Project 20.14080 (Washington, D.C.: U.S. Department of Transportation, Pipeline Hazardous Materials Safety Administration, 2011).

long will likely stop growing under a static load but will grow at a rate consistent with corrosion fatigue under a cyclic load.

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

2.3 Federal Regulations Governing Hazardous Liquid Pipelines

The actions an operator must take to address integrity issues for liquid pipelines are described in 49 CFR 195.452(h). In accordance with these requirements:

an operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long term integrity of the pipeline.

In response to API's comments during PHMSA's rulemaking process, PHMSA amended its integrity management rule by replacing the word "repair" with "remediate." In the preamble¹¹² to its rulemaking, PHMSA stated that "although actions may consist of repair, other actions such as further testing and evaluation, environmental changes, operational changes or administrative changes could be appropriate."

PHMSA also stated that "remediate can encompass a broad range of actions, which include mitigative measures as well as repair" but that it "firmly believes that a repair is necessary to address many anomalies." However, PHMSA did not identify which anomalies should be repaired.

Title 49 CFR 195.452(h)(4)(i) requires immediate repair for certain conditions, including "metal loss greater than 80 percent of the nominal wall regardless of dimensions" and when "a calculation of remaining strength of the pipe shows a predicted burst pressure less than the established [MOP] at the location of the anomaly." The regulation also identifies two acceptable methods for calculating the remaining strength of corroded pipe. The regulation does not provide an acceptable method for recalculating the remaining strength of cracked pipe.

Title 49 CFR 195.452(h)(4)(iii) addresses nine conditions that require remediation within 180 days. Four of these are the following:

(D) A calculation of the remaining strength of the pipe that shows an operating pressure that is less than the current established [MOP] at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/[American National Standards Institute] B31G ("Manual for

¹¹² *Federal Register*, vol. 65, no. 232 (December 1, 2000), p. 75377.

Determining the Remaining Strength of Corroded Pipelines” (1991)) or [American Gas Association] Pipeline Research Committee Project PR-3-805 (“A Modified Criterion for evaluating the Remaining Strength of Corroded Pipe” (December 1989)).

(G) Corrosion of or along a longitudinal seam weld.

(H) A gouge or a groove greater than 12.5 percent of nominal wall.

(I) A potential crack indication that when excavated is determined to be a crack.

During a meeting with NTSB investigators, PHMSA’s director of engineering and research stated that PHMSA expects that all cracks will be excavated. However, Enbridge was not excavating all features that had a high probability of being a crack.

Title 49 CFR 195.452(h)(4)(iii) does not address the size, depth, location, or suitable engineering assessment methods associated with the predicted failure pressure or prioritization of crack defects as it does with corrosion defects. The regulation addresses cracks as potential cracks that when excavated are determined to be cracks but does not address what constitutes potential cracks or whether excavation is required of all cracks—an expectation expressed by PHMSA’s director of engineering and research. Because the regulation is less explicit regarding the assessment of crack features, it does not clearly state the safety margin that should be applied to a predicted failure pressure, as it does with corrosion, when performing engineering assessments of crack defects. Because the regulation is less prescriptive with respect to the remediation of crack features, the Enbridge crack management program used different and inconsistent excavation criteria for cracks versus corrosion. Enbridge assessed cracking by using fitness-for-service methods that applied a lower margin of safety to the predicted failure pressure than would have been applied to corrosion features assessed under the same section of the regulations.

Therefore, the NTSB concludes 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.

PHMSA had inspected Enbridge’s integrity management program twice prior to the Marshall accident. During PHMSA’s first integrity management inspection of Enbridge in 2003 and during its second comprehensive integrity management inspection of Enbridge in 2006, PHMSA identified deficiencies involving Enbridge’s inadequate incorporation of data from all in-line inspections and tests. For example, after the 2003 inspection, PHMSA stated, “Enbridge’s information analysis procedures did not adequately consider data from other inspections and tests. Also, the process of evaluation of each pipeline segment by analyzing all available data was insufficient to gain a complete understanding of pipeline integrity.” After the 2006 inspection, PHMSA stated, “In effect, Enbridge [integrity management]-related groups operate semi-independently, and it is not clear that overall integration of knowledge and data is occurring on a consistent basis.” However, no further followup or verification of any corrective actions by Enbridge was conducted by PHMSA. In addition, Enbridge had notified PHMSA of

the introduction of changes to the engineering assessment of crack defects, following the Cohasset accident in 2002; however, no evidence was found that PHMSA asked Enbridge for justification in choosing a lower safety margin for the crack excavation criteria versus that of the corrosion excavation criteria.

Therefore, the NTSB concludes that PHMSA failed to pursue findings from previous inspections and did not require Enbridge to excavate pipe segments with injurious crack defects.

Based on its findings, the NTSB recommends 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.

PHMSA states the following in 49 CFR 195.452(h)(2):

Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

The regulation does not provide an upper limit to the number of days that an operator can take to complete the determination of threats on the pipeline, only that it must have information within 180 days. In addition, the regulation does not state whether the operator must act when a partial assessment has determined threats to the integrity of the pipeline. As written, the regulation allows a pipeline operating company to define what constitutes an “assessment” of its pipeline system and to delay corrective integrity actions.

If pressure restrictions are imposed to maintain the integrity of a pipeline, 49 CFR 195.452(h)(1)(ii) requires that pressure restrictions extending beyond 365 days be communicated to PHMSA. Enbridge filed a notice of long-term pressure reduction with PHMSA on July 15, 2010, 1 year following what it defined as the “discovery of condition” and the date when pressure restrictions were first imposed on Line 6B to safeguard the pipeline from corrosion defects. These pressure restrictions were imposed on July 17, 2009, more than 600 days after the original October 13, 2007,¹¹³ in-line inspection that identified the defects requiring pressure restrictions and 463 days beyond the 180-day “discovery of condition” deadline. Only through this long-term pressure restriction notification process did PHMSA learn

¹¹³ The 2007 MFL corrosion inspection was a followup in-line inspection to a 2004 inspection of Line 6B, which included some readings with echo-loss problems that impacted the reported depth. The 2007 in-line inspection was originally intended as a “fill-in” to supplement the 2004 inspection.

of the numerous delays to its original date-of-discovery deadline (April 10, 2008), which Enbridge stated were due to revisions and reissues of the 2007 in-line corrosion inspection report.

Enbridge was not required to notify PHMSA that it had exceeded the 180-day “discovery of condition” deadline because Enbridge stated that the revisions constituted inadequate information. However, a portion of the 2007 in-line inspection was unaffected by the errors that required the revisions and could have been used to impose pressure restrictions. The NTSB recognizes that the tool vendor has a role in the operator meeting the deadlines that are established by the “discovery of condition” rule; however, when defects are time-dependent, the regulator should be informed when delays exceed 180 days.

Therefore, the NTSB concludes that Enbridge’s delayed reporting of the “discovery of condition” by more than 460 days indicates that Enbridge’s interpretation of the current regulation delayed the repair of the pipeline.

The NTSB is concerned that other pipeline operators also may interpret the current regulation in a manner that delays defect repairs on a pipeline. Therefore, the NTSB recommends that PHMSA revise 49 CFR 195.452(h)(2), the “discovery of condition,” to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.

2.4 Deficiencies in the Integrity Management Program

The Enbridge crack management plan operated under the premise that defects in an aging pipeline with disbonded coating could be managed using a single in-line inspection technology and that prioritization of crack defects for excavation and remediation could be effectively managed through engineering assessments based strictly on the crack tool inspection data.

The program did not account for errors associated with in-line inspections and the interaction of multiple defects on a pipeline. The 51.6-inch-long crack-like feature that eventually led to the Line 6B rupture was one of six features that had been detected on the ruptured segment during an in-line inspection conducted by Enbridge’s integrity management program in 2005. Non-detection and improper classification of the defect are inherent risks when relying solely on in-line inspection data to ensure the integrity of the pipeline, yet for nearly 5 years following the inspection, the integrity management program failed to identify the 51.6-inch crack feature located adjacent to the weld as a threat to the pipeline. The Enbridge integrity management program relied entirely on the 2005 USCD tool inspection data and the engineering assessment methods, which applied a lower margin of safety than was applied under the corrosion management program, and analyzed the pipeline integrity without accounting for tool inaccuracies, validating the reported wall thickness, or considering interacting threats. Had the Enbridge integrity management program included any of these aspects, the crack-like defect that eventually resulted in the ruptured pipeline segment in Marshall might have been identified and addressed.

2.4.1 Engineering Assessment of Cracks and Margin of Safety

Enbridge applied a lower margin of safety when assessing crack defects versus when assessing corrosion defects. The Enbridge integrity crack management group calculated the predicted failure pressure for each reported defect from data supplied following in-line inspections. From these calculations, Enbridge would select and prioritize pipeline segments for excavation.¹¹⁴ To Enbridge, the excavation of a pipeline segment would expose the segment and would include a visual inspection and a nondestructive examination¹¹⁵ for cracks (including SCC) and corrosion. The results from these field assessments were sent to the integrity crack management group and used to assess tool accuracy and to make decisions for repairing the defect.

All crack-like features that had a predicted failure pressure that was calculated to be less than the hydrostatic test pressure of the pipeline segment were scheduled to be excavated.¹¹⁶ Hydrostatic test pressure is defined by 49 CFR 195.304 as a minimum pressure of 1.25 times the MOP of the pipeline. The Line 6B rupture segment had a MOP of 624 psig with a stated hydrostatic test pressure of 796 psig (or 1.28 times the MOP). By comparison, the corrosion defects on Line 6B were required to be excavated and remediated in accordance with 49 CFR 195.452(h)(4)(i)(B) when calculated predicted failure pressures were less than 1.39 times the MOP of the pipeline or SMYS (867 psig, the pressure that equates to a circumferential stress equivalent to the SMYS of the pipe). Therefore, the calculated margin of safety for a corrosion feature was 11 percent higher than that of a crack feature.

The use of a lower safety factor for crack defects is inconsistent with the growth rate assumptions used by the Enbridge crack management and corrosion management groups. The crack growth rate used in the engineering assessments of cracks is greater than the maximum corrosion growth rate assumption. Furthermore, Enbridge has stated that a greater range of possible errors is associated with crack tools and that a higher reliability exists with corrosion tools. However, neither of these factors was reflected in the lower safety margin used by Enbridge when assessing cracks than when assessing corrosion. A larger margin of safety would have resulted in a larger number of crack defects being eligible for excavation and examination.

2.4.2 In-line Inspection Tool Tolerances

To account for uncertainty in the depth sizing of crack features, the USCD tool has a stated tolerance of ± 0.02 inch. However, Enbridge did not include this tolerance in its engineering assessment of the crack defects from the 2005 USCD in-line inspection report. Enbridge applied an engineering assessment method that used the maximum depth reported by the tool, without incorporating tool tolerance to predict a failure pressure on the pipeline. If this

¹¹⁴ A reported depth greater than 40 percent of the wall thickness was another trigger that was used to select crack features for excavation. None of the crack-like defects identified on the rupture segment had a reported depth greater than 40 percent.

¹¹⁵ Magnetic particle testing was performed for SCC, and a USWM tool was used to record remaining wall thickness.

¹¹⁶ Five features were excluded with the comment “surface breaking lamination.” Enbridge stated that experience had shown these features are mid-wall laminations with no surface-breaking component.

predicted failure pressure was lower than the hydrostatic test pressure, rather than excavate the crack, Enbridge requested that PII analyze the in-line inspection data again and refine the estimated crack depth or crack profile. This was the case for the 9.3-inch-long crack and deepest of the six features identified in 2005. The Enbridge method of engineering assessment used the tool-reported crack depths as actual without accounting for tool error. However, PII has stated that the tool tolerance should be incorporated in the reported crack depth. If tool tolerance is not accounted for during an engineering assessment, the size of some defects may be underestimated, resulting in a predicted failure pressure greater than the actual failure pressure. If the predicted failure pressure is greater than the hydrostatic test pressure, these defects may not get excavated and evaluated.

2.4.3 Improper Wall Thickness

Enbridge used the wall thickness reported by the 2005 USCD tool (0.285 inch) in its fitness-for-purpose failure pressure assessment and crack-growth calculations used to prepare the excavation list. The reported wall thickness from the USCD tool appeared in the in-line inspection report as a constant for the entire length of the ruptured segment. But, wall thickness can vary significantly along the length of a pipe, and while this value was within the specification tolerance for this pipe, Enbridge did not compare the value to the values reported by the 2004 USWM wall measurement tool. The 2005 USCD tool-reported wall thickness of 0.285 inch was 0.035 inch thicker than the nominal wall thickness of 0.25 inch. By using the tool-reported wall thickness instead of the nominal, Enbridge effectively added another 14 percent to the maximum allowable pressure rating for the pipeline segment. The Enbridge crack management program did not compare the tool-reported wall thickness in the 2004 in-line corrosion inspection, which measured local wall thickness, with the 2005 in-line crack-inspection reported wall thickness. Enbridge also did not apply a nominal wall thickness during the engineering assessment of the 2005 in-line inspection data.

2.4.4 Corrosion and Cracking Interactions

In 2005, Enbridge had no procedure that accounted for the interaction between corrosion and cracking and the potential influence on crack depth reporting. The USCD tool Enbridge used in 2005 measured the crack depth from the surface adjacent to the crack; therefore, if the pipe's wall was free of corrosion, then the estimated depth reported by the crack tool closely matched the actual crack depth. However, if corrosion had caused wall loss on the surface adjacent to the crack, then the crack depth measured by the tool was less than the actual depth of the crack relative to the original surface of the outer wall. The 2004 corrosion inspection results and the 2005 crack inspection results showed areas where cracks and corrosion overlapped in regions directly over the ruptured area.

Enbridge did not have a procedure to account for wall loss due to corrosion when it was evaluating the in-line inspection crack-tool-reported data and was preparing the excavation list. Considering interacting threats in addition to individual threats to pipeline integrity provides a more accurate assessment of potential hazards. The practice is also recognized in Federal regulations and industry guidance, which highlight the importance of integrating all available information in an integrity management program. According to API 1160, "The integration of

information is a key component for managing system integrity.” API 1160 further notes that it is important to integrate all available information from various sources in the decision-making process; in particular, an operator should compare the “coincident occurrence” of suspected high-risk conditions. Title 49 CFR 195.452(f)(3) states that one of the minimum requirements of an integrity management program is “an analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure.”

2.4.5 Crack Growth Rate Not Considered

Enbridge integrity management did not adequately address the effects of a corrosive environment on crack growth rates. In its 2005 USCD engineering assessment, the Enbridge crack management group used a fatigue crack growth model to predict the remaining life of the pipeline to ensure that in-line inspection intervals were selected at a frequency that allowed it to monitor crack growth. Enbridge did not calculate crack growth rates for other potential crack mechanisms (such as SCC or corrosion fatigue). In 2011, an Enbridge consultant conducted a systemwide threat assessment review to examine the pipeline integrity threats. The threat assessment used data from an existing Enbridge leak-report database, which contained data collected from 1984 to 2010. According to the threat assessment, the “environmentally assisted cracking mechanism that is most prevalent along Enbridge’s liquid pipeline system is either near-neutral pH SCC or corrosion fatigue.” Much of the information used to draw this conclusion was available to the Enbridge crack management group. However, until the time of the Marshall accident, Enbridge’s crack management plan focused only on fatigue cracks. The growth rates of environmentally assisted cracks (such as corrosion fatigue cracks) can be an order of magnitude or more greater than nominal fatigue crack growth rates.¹¹⁷ Because Enbridge did not include crack growth from corrosion fatigue in its analysis, some cracks in the pipeline could grow significantly faster than predicted under the Enbridge engineering assessment. Enbridge’s crack management program and reinspection interval selection is inadequate because it fails to consider all potential crack growth mechanisms that are prevalent in its pipeline.

2.4.6 Need for Continuous Reassessment

The TSB’s investigation of the 2007 rupture of Enbridge’s Line 3 in Glenavon, Saskatchewan, identified limitations of in-line inspection tools and of the engineering assessment methods Enbridge used to evaluate pipeline safety based on the inspection reports. The Enbridge USCD tool inspection conducted in 2006 on Line 3 measured the depth of the defect that ultimately failed and reported it within a depth range of 12.5 to 25 percent of estimated wall thickness. Enbridge had conducted an engineering assessment of the crack defect and determined that the predicted failure pressure of the pipeline segment was greater than the hydrostatic test pressure; consequently, the feature was not excavated.

Enbridge changed its process, based on the findings in the 2007 TSB report, to include tool tolerances during an engineering assessment of Line 3. However, the changes implemented

¹¹⁷ W. Chen, *Report on Achieving Maximum Crack Remediation Effect from Optimized Hydrotesting*, prepared by University of Alberta, Department of Chemical and Materials Engineering, Edmonton, Alberta, for the U.S. Department of Transportation, PHMSA, June 15, 2011.

on Line 3 because of the Glenavon accident were never applied retroactively to the 2005 in-line inspection data collected for Line 6B. The Enbridge integrity management program did not incorporate a process of continuous reassessment to all of its pipeline engineering assessments when it neglected to apply the revised crack assessment methods to Line 6B. API Standard 1160, titled “Managing System Integrity for Hazardous Liquid Pipelines,” defines pipeline integrity risk assessment as a continuous process and risk analysis as a continuous reassessment process. The standard also states that any applicable information or experience “should be factored into the understanding of system risks.”

2.4.7 Effect of Integrity Management Deficiencies

To examine the role that some of the deficiencies described above played in Enbridge not identifying the crack-like features as an integrity threat between 2005 and 2010, the NTSB conducted an engineering assessment of the six crack-like features identified in the 2005 in-line inspection of the ruptured segment. Variables such as tool tolerances, nominal wall thickness, and interaction of corrosion and cracking were evaluated, using Enbridge’s analysis software and assumptions from 2005, to determine whether the 51.6-inch crack feature would have triggered an excavation of the ruptured segment. The results of the assessment showed any one of the variations used in the predicted failure pressure calculations would have resulted in a calculated failure pressure below the stated Enbridge criteria (that is, hydrostatic test pressure) and required that the rupture feature be placed on an excavation list.

In addition, the NTSB examined the impacts to the engineering assessment when the excavation criteria for cracks were equal to the excavation criteria for corrosion. The predicted failure pressure results of the Enbridge 2005 engineering assessment for the six crack-like features were compared against a threshold of 1.39 times the MOP. The findings show that the 51.6-inch-long crack-like defect that resulted in the rupture had a predicted failure pressure that was less than 1.39 times the MOP but greater than the hydrostatic test pressure.¹¹⁸ Had Enbridge’s crack management program used a margin of safety equivalent to the margin of safety used in the corrosion management program (1.39 times MOP), the crack-like feature that eventually grew to failure would have been identified for excavation.

Enbridge currently includes an allowance for tool tolerance, developed from field excavations, with the crack depth when it is analyzing crack features. By adding the tool tolerance to the crack depth, the crack depth estimates used in the analysis are increased and some uncertainty associated with the in-line inspection tool’s sizing of the defects is mitigated. Enbridge now uses the lesser of either the nominal wall thickness or the remaining wall thickness reported in the USWM tool inspection report when performing engineering assessments of crack defects.

Since the accident, Enbridge has added an analysis of SCC to its process for analyzing crack growth in addition to its analysis for fatigue crack growth. However, Enbridge still does not consider corrosion fatigue in its analysis of crack growth. Because corrosion fatigue cracks

¹¹⁸ Crack defects from in-line inspection reports had to have a predicted or calculated failure pressure of less than hydrostatic test pressure to be excavated in 2005.

can grow faster than SCC or fatigue cracks, Enbridge's current analysis of crack growth can still underestimate crack growth rates in areas of corrosion.

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

The NTSB recommends that Enbridge revise its integrity management program to ensure the integrity of its hazardous liquid pipelines as follows: (1) implement, as part of the excavation selection process, a safety margin that conservatively takes into account the uncertainties associated with the sizing of crack defects from in-line inspections; (2) implement procedures that apply a continuous reassessment approach to immediately incorporate any new relevant information as it becomes available and reevaluate the integrity of all pipelines within the program; (3) develop and implement a methodology that includes local corrosion wall loss in addition to the crack depth when performing engineering assessments of crack defects coincident with areas of corrosion; and (4) develop and implement a corrosion fatigue model for pipelines under cyclic loading that estimates growth rates for cracks that coincide with areas of corrosion when determining reinspection intervals.

To ensure that the approach adopted by Enbridge under the integrity management program is consistent with PHMSA's regulations, as recommended in the above safety recommendation, the NTSB believes that it is prudent for the regulator to perform an inspection of the revised Enbridge integrity management program. Therefore, the NTSB recommends that PHMSA conduct a comprehensive inspection of Enbridge's integrity management program after it is revised in accordance with the above safety recommendation.

Typically, different tools, techniques, and vendors are involved in performing various in-line inspections of a pipeline to assess its integrity. The NTSB concludes that to improve pipeline safety, a uniform and systematic approach in evaluating data for various types of in-line inspection tools is necessary to determine the effect of the interaction of various threats to a pipeline. The Pipeline Research Council International has been involved in energy pipelines research programs since 1952; it also works with many trade associations such as the American Gas Association, the Interstate Natural Gas Association of America, and NACE International. The NTSB therefore recommends that the Pipeline Research Council International conduct a review of various in-line inspection tools and technologies—including, but not limited to, tool tolerance, the probability of detection, and the probability of identification—and provide a model with detailed step-by-step procedures to pipeline operators for evaluating the effect of interacting corrosion and crack threats on the integrity of pipelines.

It is NTSB's expectation that the safety recommendation to PHMSA to revise 49 CFR 195.452 would require all hazardous liquid pipeline operators to correct deficiencies in their integrity management programs. However, the NTSB recognizes the effort and the time required to make these revisions. The NTSB concludes that pipeline operators should not wait until PHMSA promulgates revisions to 49 CFR 195.452 before taking action to improve pipeline safety. Therefore, the NTSB recommends that PHMSA issue an advisory bulletin to all

hazardous liquid and natural gas pipeline operators describing the circumstances of the accident in Marshall, Michigan—including the deficiencies observed in Enbridge’s integrity management program—and ask them to take appropriate action to eliminate similar deficiencies.

2.5 Mischaracterization of the Crack Feature

According to PII, a “crack-like” characterization was indicative of a single linear crack whereas a “crack-field” characterization implied that the feature was made up of a cluster of small cracks typically associated with SCC. All six features identified on the ruptured segment, including the 51.6-inch-long feature that grew to failure, were initially characterized as “crack-field” features by the junior analyst; however, a supervisor changed the final report to read “crack-like” features. When PII identified a feature as a “crack-field,” PII also reported the length of the longest individual crack within the cluster. Enbridge used a criterion of 2.5 inches for the longest crack as a trigger for excavation of “crack-field” defects.

After the Marshall accident, PII reexamined the in-line inspection data and determined that the features were misclassified. Based on this examination of the failure defect, the rupture feature would have had a longest indication¹¹⁹ that measured 3.5 inches. Because this longest indication within the cluster was greater than the Enbridge excavation criteria for “crack-field” features, the 51.6-inch feature would likely have been excavated by Enbridge in 2005.

Therefore, the NTSB concludes 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.

2.6 Control Center

For over 17 hours, Enbridge control center staff directly involved with operating Line 6B did not recognize that the pipeline had ruptured. During this time, the control center staff believed that column separation was present in the pipeline and that the pipeline could and should be started. After 17 hours, the control center received a call from a gas utility technician stating that he had found oil on the ground.

The NTSB examined Enbridge’s control center operations to understand how the staff failed to detect the rupture. The investigation found that the control center staff’s errors—the protracted misinterpretation of the pipeline status and the two pipeline startups (each of which pumped additional crude oil into the environment and exacerbated the damage caused by the rupture)—were influenced by multiple factors. The investigation examined the Enbridge control center staff’s team performance and training, preparedness to detect pipeline ruptures, and tolerance for procedural deviance.

¹¹⁹ *Longest indication* refers to the longest crack within the cluster of cracks of a “crack-field” defect.

2.6.1 Team Performance

The control center staff involved in pipeline operations consisted of control center operators, terminal operators, MBS analysts, shift leads, and supervisors. Control center operators were given the authority to decide when to terminate pipeline product flow with input from the MBS analysts. That is, operators had the final authority to terminate flow without the fear of repercussion from the company. The control center operators were to use input from the MBS analysts, who were responsible for determining the validity of MBS alarms. When MBS alarms occurred, operators were to consult with MBS analysts and to inform shift leads. If shift leads needed assistance in making operating decisions, they consulted with and obtained approval from higher-level supervisors; an on-call supervisor was available outside of normal business hours. Shift leads were to oversee and facilitate the work of the control center operators.

During shift B, MBS alarms associated with the Line 6B rupture appeared on the operator's SCADA display. Operator B1 notified the MBS analyst, who determined that the alarms were due to column separation. The control center operator and the shift lead's subsequent actions regarding Line 6B were consistent with, and largely influenced by, the MBS analyst's determination of the cause of the MBS alarm and his characterization of the alarm as false. Later, when shift lead B2 discussed with the on-call supervisor the inability to merge the separated oil columns in Line 6B, the on-call supervisor deferred to MBS analyst B's explanation for the column separation and the analyst's suggestion that line pressure be increased to compensate for the inactive Niles PS. The on-call supervisor approved the shift lead's request to authorize starting up the line again.

The transcript of the conversations regarding the Line 6B second startup and the actions and decisions of those involved in operating Line 6B during the time of the accident reveal a control center team that performed ineffectively during the events of this accident. At the time of the accident, the MBS analyst became the de facto team leader because his conclusions provided an explanation for the Line 6B situation that affected the team's perceptions and actions regarding the line. More important, the MBS analyst provided more than an assessment of whether the alarm was valid—he proposed that the alarm was caused by column separation, and he proposed a solution (that is, starting up the line flow with greater pump power than previously had been used). The control center operator and shift lead eventually accepted the MBS analyst's proposed cause and course of action, despite the fact that the MBS analyst was not assigned a team leadership position. The control center operator, shift lead, and supervisor did not seek alternative explanations of the MBS alarm. Given the deference of the team to someone who had exceeded his area of responsibility by providing an explanation for the MBS alarm and a proposed solution, lack of effective team performance was evident. Therefore, the NTSB concludes that the ineffective performance of control center staff led them to misinterpret the rupture as a column separation, which led them to attempt two subsequent startups of the line.

The NTSB has investigated previous accidents in which breakdowns in team performance occurred. In these accidents, team leaders transferred their authority to subordinates who they believed possessed more expertise than they did in the circumstances they were encountering. During restricted visibility conditions at a Detroit airport, the captain of a transport

aircraft deferred to his first officer’s navigation on the ground.¹²⁰ The captain had just been cleared to return to flight operations and had completed his captain recertification process after an extended absence. The first officer unknowingly guided the aircraft onto an active runway. The airplane was then struck by an aircraft that was taking off.

In a recent marine accident,¹²¹ a licensed deck officer (the third mate), who was new to the vessel and on his first watch, deferred the vessel navigation to the helmsman who did not have a mate’s license and had been on the vessel for 17 months. The helmsman steered and navigated the vessel onto rocks, and the vessel grounded.

Similarly in the Marshall accident, the assigned leader of the team (the on-call supervisor) deferred his authority to the MBS analyst. The two individuals essentially reversed roles, as was seen in the two previously mentioned accidents.

The ineffective performance of the control center team in this accident is consistent with human factors research on team performance, which has shown that the quality of team performance is influenced by team structure and team leadership. In essence, the effectiveness of the team leader (that is, the person responsible for defining goals, organizing resources to maximize performance, and guiding individuals toward those goals) influences the effectiveness of the team. Further, team coordination in this accident had broken down as well, such that other team members failed to recognize that the MBS analyst had incorrectly interpreted the MBS alarm and consequently had proposed an improper solution to its real cause. In a 2007 study, researchers stated the following:

...coordination is the behavioral mechanism team members use to orchestrate their performance requirements. When coordination breakdowns occur, this can lead to errors, missed steps or procedures, and lost time... . For example, if one team member makes an error, this will likely translate to another team member error if it is not caught and corrected.¹²²

In this accident, none of the control center team members involved in Line 6B operations recognized that the cause of the alarms was a rupture and that starting the line would only exacerbate, rather than correct, the underlying condition.

Human factors research also has shown that team effectiveness and performance levels are enhanced by team training.¹²³ Although Enbridge control center staff worked in teams, they

¹²⁰ Northwest Airlines, Inc., *Flights 1482 and 299, Runway Incursion and Collision, Detroit Metropolitan/Wayne County Airport, Romulus, Michigan, December 3, 1990*, Aviation Accident Report NTSB/AAR-91/05 (Washington, D.C.: National Transportation Safety Board, 1991).

¹²¹ *Grounding of U.S. Passenger Vessel Empress of the North, Intersection of Lynn Canal and Icy Strait, Southeast Alaska, May 14, 2007*, Marine Accident Report NTSB/MAR-08/02 (Washington, D.C.: National Transportation Safety Board, 2008).

¹²² K.A. Wilson and others, “Errors in the Heat of Battle: Taking a Closer Look at Shared Cognition Breakdowns Through Teamwork,” *Human Factors*, vol. 49, no. 2 (2007), pp. 243–256.

¹²³ (a) E. Salas, N.J. Cooke, and M.A. Rosen, (2008) On Teams, Teamwork, and Team Performance: Discoveries and Developments,” *Human Factors*, vol. 50, no. 3 (2008), pp. 540–547. (b) E. Salas, N.J. Cooke, and J.C. Gorman, “The Science of Team Performance: Progress And the Need for More . . .,” *Human Factors*, vol. 52, no. 2 (2010), pp. 344–346. (c) C.R. Paris, E. Salas, and J.A. Cannon-Bowers, “Teamwork in Multi-Person Systems: A Review and Analysis,” *Ergonomics*, vol. 43, no. 8 (2000), pp. 1052–1075.

were not trained to do so, and PHMSA’s regulations did not require Enbridge to provide team training. Enbridge trained its operators primarily individually, providing them with the knowledge and the skills needed to operate the pipelines, using simulated operational scenarios with instructors playing the roles of other control center staff. Control center operators, MBS analysts, shift leads, and supervisors did not train together. Therefore, the NTSB concludes that Enbridge failed to train control center staff in team performance, thereby inadequately preparing the control center staff to perform effectively as a team when effective team performance was most needed.

Further, the ineffective team performance noted in this accident was similar to the inadequacies of the SCADA control center staff the NTSB noted in its investigation of the September 9, 2010, gas pipeline rupture and fire in San Bruno, California. In that accident, the NTSB found “that it was evident from the communications between the SCADA center staff, the dispatch center, and various other PG&E employees that the roles and responsibilities for dealing with such emergencies were poorly defined” and that “PG&E’s response to the Line 132 break lacked a command structure with defined leadership and support responsibilities within the SCADA center.”¹²⁴

Given the team performance deficiencies noted in both the San Bruno and the Marshall accidents and the pivotal roles these deficiencies played in control center staff errors, there is a clear need for pipeline companies to address team performance in their operator training. In 14 CFR 121.404, the FAA requires airline pilots to be trained in team performance, which is referred to as crew resource management (CRM) in aviation, and provides guidance to airlines on developing, implementing, reinforcing, and assessing team performance (in the January 22, 2004, FAA Advisory Circular 120-51e, “Crew Resource Management Training”). Team training prepares people to work efficiently and effectively as members of a group. CRM in commercial aviation seeks to reduce human errors in the cockpit by improving interpersonal communications, leadership skills, and human decision-making. The essential elements of CRM training include the following:

- Learning to function as members of teams, not as a collection of technically competent individuals.
- Instructing how to behave in ways that foster crew effectiveness.
- Providing opportunities to practice the skills necessary to be effective team leaders and team followers.
- Training on effective team behaviors during normal, routine operations.

CRM programs have been developed in several transportation areas. For passenger flight operations, 14 CFR 121.419, 121.421, and 121.422, require pilots, flight attendants, and dispatchers to participate in CRM training. In marine transportation, the Coast Guard requires licensed mariners on internationally operating vessels to participate in bridge resource management (BRM) training. In railroad transportation, the Federal Railroad Administration has sponsored research to develop rail CRM programs. Additionally, there has been substantial

¹²⁴ NTSB/PAR-11/01, p. 98.

research on the effectiveness of CRM programs.¹²⁵ There have been considerable materials published on the objectives and basic curriculum of team training through CRM, and similar curricula is available in several transportation modes that prepare individuals in team practice sessions to work together as teams. Therefore, the NTSB recommends that PHMSA develop requirements for team training of control center staff involved in pipeline operations similar to those used in other transportation modes.

2.6.2 Training

Few of the Enbridge control center operators or shift leads who were involved in Line 6B operations had experienced a pipeline rupture before this accident. The majority of operators the NTSB interviewed indicated that their primary exposure to leaks occurred during regularly scheduled annual simulated exercises. Control center operators commented on the relative frequency of the column separations they had experienced, particularly in areas of changing elevation (not a factor in this accident) and at times during line startups and shutdowns (a factor in this accident). Moreover, some control center operators stated that MBS alarms sometimes occurred during transient conditions, such as pipeline startups or shutdowns, and often were explained by the MBS analysts as being related to pressure transmitter problems or column separations. API RP 1130 discusses control center operator complacency and leak detection credibility due to an increased frequency of leak detection alarms and stresses the importance of control center operator training on leak detection systems. Given the infrequency of actual ruptures and the relatively high frequency of MBS alarms encountered during line startups and shutdowns, it was natural for control center staff to assume the MBS alarms for Line 6B had been caused by column separation. Consequently, the MBS analysts' incorrect interpretation of the MBS alarms as resulting from column separation was readily accepted by operators, shift leads, and on-call supervisors without additional analysis. The evidence suggests that the control center staff's repeated experiences with MBS alarms caused by column separation rather than a rupture affected their ability to interpret the alarms correctly.

In accordance with PHMSA regulations, Enbridge control center operators were given extensive training in pipeline operations, which included regular testing of their knowledge and skills. After becoming operators, they were required to demonstrate continued operating knowledge and skills through triennial operator requalification. By contrast, shift leads, MBS analysts, and supervisors were not required to demonstrate continued proficiency. The transcript of control center conversation following the first startup revealed that the on-call supervisor did not have the knowledge and technical skills necessary to properly advise shift lead B2 and question MBS analyst B about pipeline operating matters. Although consistent with PHMSA requirements, Enbridge's practice of requiring only some of the decision-makers involved in pipeline operations to demonstrate their knowledge and skills through operator qualifications is counter to safe operating principles. Therefore, the NTSB concludes that Enbridge failed to ensure that all control center staff had adequate knowledge, skills, and abilities to recognize and

¹²⁵ For example, (a) E. Salas and others, "Does Crew Resource Management Training Work? An Update, an Extension, and Some Critical Needs," *Human Factors*, vol. 48, no. 2 (2006), pp. 392-412. (b) P. O'Connor and others, "Crew Resource Management Training Effectiveness: A Meta-Analysis and Some Critical Needs," *International Journal of Aviation Psychology*, vol. 184, no. 4. (2008), pp. 353-368.

address pipeline leaks, and their limited exposure to meaningful leak recognition training diminished their ability to correctly identify the cause of the MBS alarms.

Consequently, the NTSB recommends that Enbridge establish a program to train control center staff as teams, semiannually, in the recognition of and response to emergency and unexpected conditions that includes SCADA system indications and MBS software.

The NTSB is also concerned that other pipeline operating companies may have a similarly inconsistent standard for maintaining proficiency among all staff involved in pipeline operational decisions. Therefore, the NTSB recommends that PHMSA extend operator qualification requirements in 49 CFR Part 195 Subpart G to all hazardous liquid and gas transmission control center staff involved in pipeline operational decisions.

2.6.3 Procedures

Failure to use available leak indications, the use of incomplete procedures, and the influence of the MBS analyst were evident in an examination of shifts A and B during the accident. At the time of the shutdown, on July 25, operators A1 and A2 received a series of nearly simultaneous SCADA pressure-related alarms near the Marshall PS indicative of a rupture. These initial alarms were followed by a 5-minute MBS alarm (a severe leak alarm) 3 minutes later. The sudden drop in pressure at the Marshall PS, a SCADA alarm of a local shutdown of the Marshall PS, and the MBS alarm were all leak triggers identified under the *Leak Triggers from SCADA Data* procedure. The occurrence of one or two leak triggers mandated that the control center operator execute the *Suspected Leak Trigger* procedure requiring that a leak be ruled out within 10 minutes or the pipeline be shut down. Three or more leak triggers required that the control center operator shut down the pipeline immediately and the shift lead make emergency notifications.

However, due to the pressure transients generated at the time of the shutdown and rupture, many of the low-pressure alarms appeared multiple times and cleared shortly after alarming. In addition, the 5-minute MBS alarm cleared on its own as the pipeline flows approached zero following the shutdown.

Nonetheless, the Line 6B SCADA console display highlighted the low pressures at the Marshall PS that remained below minimum suction pressure and indicated an abnormal operating condition. Because the pressure alarms that initially appeared at the SCADA console had cleared, the control center operator attributed them to the shutdown. When MBS analyst A explained to operator A1 that the leak detection alarm was due to column separation at the Marshall PS, operator A1 assumed that the low pressure and remaining alarm indications were also symptoms of a column separation condition. The supervisor of the MBS group stated that it was commonly understood that leak detection alarms clear following a shutdown; however, this was not documented in either the control center procedure or the MBS analysts' procedure.

During the two startups on shift B, there were several SCADA indications of a leak, including zero pressure at the Marshall PS, the lack of pressure downstream of the Marshall PS when the line had been operated for 10 minutes, and the volume differences (between the amount of oil pumped into Line 6B and the amounts received at the delivery locations). Additionally

repeated, active 5-minute, 20-minute, and 2-hour MBS alarms were received during the course of the two start attempts. Active MBS alarms were identified under the control center *Leak Triggers from SCADA Data* procedure; however, the inability to increase pressure downstream of the last PS and the excessive volume differences were not in that procedure. The *Suspected Column Separation* procedure required the control center operator to shut Line 6B down within 10 minutes, but because shift lead B1 decided to use an unapproved draft version of the *Starting Up Into Known Column Separation* procedure, the 10-minute limitation was exceeded.

During the shutdown on shift A and the startups on shift B, both MBS analysts had declared the presence of column separation in the pipeline, and, in both instances, the control center operators did not first examine elevation profiles on SCADA, historical SCADA trends of pressures and flows, or historical alarm logs to rule out a leak. Elevation profiles revealed that the Marshall area was not conducive to column separation, and historical alarm records showed that MBS alarms on Line 6B were rare. Adding to the confusion were control center procedures for MBS indications that were not fully integrated with the MBS procedures. The procedures were developed by different groups and used inconsistent language to describe MBS alarms and to explain how to determine whether the alarms were “valid” or “false.” The inconsistent language contributed to confused roles and responsibilities when control center staff analyzed leak alarms. Although column separation and ruptures have similar SCADA indications, a rupture has far greater consequences. The Enbridge procedures did not ensure that leaks were ruled out first, under all circumstances.

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

The MBS reported flow imbalances in the pipeline; to do so, the software relied on real-time SCADA pipeline pressures and flows to calculate these imbalances. Differences between the configuration of the MBS system and the actual pipeline result in either false MBS alarms or additional indications of column separation erroneously generated. To generate credible leak detection alarms, the MBS software and the SCADA system must use identical pipeline pressures and flows. MBS analyst B realized the actual pipeline configuration and pressures did not match that of the leak detection software during the first startup. The MBS analyst had to override the pressure values in the MBS software to represent the valve closure at the Niles PS. This action was completed about the time Line 6B was shut down following the first startup. The difference in pressure readings contributed to a reduced credibility of Enbridge’s MBS alarms during the first startup because it resulted in additional column separation indications on Line 6B.

The MBS analyst on shift B informed the on-call supervisor, at the shift lead’s request, that the MBS alarms following the first startup of Line 6B were “false alarms” because column separation was present in the pipeline. MBS analyst B based his characterization of the alarm on a known limitation of pressure transient leak detection models, which is that column separations can render the MBS unreliable and reduce the credibility of the leak detection alarms. The API recognizes that a CPM alarm is probably the most complex alarm that a control center operator will experience. To correctly recognize and respond to this type of alarm, the API believes that

an operator needs specific training and appropriate reference material. MBS analyst B told NTSB investigators about this alarm's complexity; however, the analyst's actions on July 26 did not reflect a valid understanding of the alarm.

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

In addition to the issues of credibility, Enbridge was confident that pipeline ruptures occurring in remote or difficult-to-access areas would have limited consequences because of its 10-minute restriction on continued pipeline operations in uncertain situations. According to Enbridge procedures, the pipeline would be shut down after 10 minutes if operational alarms remained unresolved. The control center staff, to some extent, and the Chicago regional manager believed that unintended product releases would be reported by outside sources (that is, either affected citizens or community officials). This belief was evident in the conversation between the shift lead and the Chicago regional manager during shift C. For example, at 10:16 a.m., on July 26, the Chicago regional manager said to shift lead C2, "... right now ... I'm not convinced. We haven't had any phone calls. I mean, it's ... perfect weather out here. Someone—if it's a rupture, someone's going to notice that, you know, and smell it." The visual confirmation of the leak did not occur until 11:17 a.m. on July 26. In the absence of that confirmation from a person located in Marshall, control center personnel discounted the possibility of a leak, largely because no external confirmation of a leak was present. Thus, the absence of information on a leak led to the belief that there was no leak, and that some other phenomenon, yet unrecognized, was causing the column separation.

Moreover, there was no evidence that any member of the control center staff sought to obtain information from anyone in the Marshall vicinity to verify the presence of a leak. Rather than actively soliciting information from sources in the Marshall area, the control center staff continued their erroneous decision-making by misinterpreting the absence of notifications from the Marshall community as actual information that there was no leak. In contrast, the first responders to the scene at Marshall, who were dispatched with knowledge of possible gas odors, actively sought information about a gas leak. Upon finding none, they believed that there was no leak, despite the fact that they detected but could not identify the type of strong odors present in the area. Their error of responding only to a gas leak and not considering other possibilities differs from the control center staff's error of using the lack of external notifications as support for a belief that Line 6B was experiencing a column separation.

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

The combination of procedural gaps, the failure to use available leak indications, and the misinterpretation of the lack of external notifications added to the control center staff's inability to recognize the rupture. Therefore, the NTSB recommends that Enbridge incorporate changes to its leak detection processes to ensure that accurate leak detection coverage is maintained during transient operations, including pipeline shutdown, pipeline startup, and column separation.

2.6.4 Tolerance for Procedural Deviance

Before this accident, Enbridge managers were confident that any pipeline leak that occurred would have limited consequences because the company had restricted pipeline operations to no more than 10 minutes when MBS alarms could not be resolved. This restriction derived from the company's experience in the 1991 Grand Rapids, Minnesota, accident and its determination that even with a pipeline rupture, 10 minutes of operating time would limit the product flow to controllable amounts.

However, control center staff did not comply with the 10-minute restriction twice on July 26, as shown by the two startups. One Enbridge control center operator told NTSB investigators that staff had become accustomed to exceeding the 10-minute restriction. Because the MBS alarms often were attributed to column separation, an operator could attempt to pump additional oil into the pipeline to restore pressure and bring the columns together, even if the process exceeded 10 minutes.

Research into the Space Shuttle Challenger accident demonstrated that, in complex systems, technical personnel can allow a "culture of deviance" to develop.¹²⁶ A researcher observed in that accident that an early decision to continue shuttle operations in violation of requirements cultivated an operating culture in which not adhering to requirements became the norm. Decisions made thereafter made it easier for shuttle personnel to avoid adhering to other requirements, thus "normalizing" the deviation from technical requirements. Ultimately, a culture of deviance from technical requirements became the operating culture of shuttle personnel.

A similar culture of deviance appears to have developed in the Enbridge control center as control center operators, shift leads, and their supervisors believed that it was acceptable to not adhere to the 10-minute restriction when given the "right" circumstances. No system can operate safely when a culture of deviance from procedural adherence has become the norm, as the evidence suggests occurred in the Enbridge control center. Therefore, the NTSB concludes that although Enbridge had procedures that required a pipeline shutdown after 10 minutes of uncertain operational status, Enbridge control center staff had developed a culture that accepted not adhering to the procedures.

2.6.5 Alcohol and Drug Testing

Enbridge did not act in accordance with 49 CFR 199.225(2)(i), which places an 8-hour time limit on postaccident alcohol testing. Specifically, specimens for alcohol testing were collected for shifts A, B, and C on the morning of July 27 and about noon on July 28; however, the specimens should have been collected in accordance with PHMSA's regulation of 8 hours by the evening of July 26 following the confirmation of the pipeline rupture. Enbridge did not provide PHMSA with an explanation for its noncompliance, but a control center supervisor told NTSB investigators that the delay occurred because the rupture was not confirmed and because staff had left the control center after their duty assignment. The NTSB believes that Enbridge had

¹²⁶ D. Vaughan, *The Challenger Launch Decision: Risky Technology, Culture, and Deviance at NASA* (Chicago: The University of Chicago Press, 1996).

adequate knowledge of the rupture and time to collect the specimens. Further, the NTSB believes that Enbridge ignored key personnel for testing, such as MBS analysts and on-call supervisors, who played critical roles in the Line 6B operations during the accident. Enbridge's postaccident drug testing, however, was in accordance with PHMSA's regulation of 32 hours. The results of the drug tests were negative. Therefore, the NTSB concludes that insufficient information was available from the postaccident alcohol testing; however, the postaccident drug testing showed that use of illegal drugs was not a factor in the accident.

In its investigation of the 2010 San Bruno pipeline accident, the NTSB learned that PG&E did not conduct postaccident alcohol testing within the required time limit and failed to provide PHMSA with an explanation for its actions. As a result, the NTSB issued two recommendations to PHMSA. The first, Safety Recommendation P-11-12, urged PHMSA to amend 49 CFR 199.105 and 49 CFR 199.225 to eliminate operator discretion with regard to testing of covered employees. The revised regulation should require drug and alcohol testing of each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The second, Safety Recommendation P-11-13, urged PHMSA to issue guidance to pipeline operating companies regarding postaccident alcohol and drug testing.

In an April 24, 2012, letter addressing PHMSA's actions in response to these safety recommendations, the NTSB stated that it understood that PHMSA was reviewing its legal authority and policy to clarify the regulatory language identified in 49 CFR 199.105(b) and 199.225(a)(1). After it completes its discussions with the U.S. Secretary of Transportation, PHMSA will clarify the regulations as needed. Pending receipt of PHMSA's intended course of action, Safety Recommendation P-11-12 was classified "Open—Acceptable Response." Because PHMSA issued Advisory Bulletin 2012-02 on February 23, 2012, which provided immediate guidance on the need for postaccident drug and alcohol testing and listed the employees covered by the rule, Safety Recommendation P-11-13 was classified "Closed—Acceptable Action." Because there is still pending action by PHMSA, no recommendation is required to correct Enbridge's deficiencies in alcohol and drug testing.

2.6.6 Work/Sleep/Wake History

The shift leads, MBS analysts, and operators involved in this accident normally worked 12-hour schedules that rotated between the day and the night shifts. That is, they worked 2 days followed by 3 nights, or 3 nights followed by 2 days, with on-duty periods beginning at either 8:00 a.m. or 8:00 p.m.¹²⁷ Procedures were in place to prevent someone from switching directly from one shift schedule to another without having at least 24 hours off duty. With such a schedule, staff were assured of 3 to 5 successive days off following completion of the fifth on-duty period. Operator A1 had worked 4 days in a row and was scheduled to work the night shift on July 26. The Line 6B operators, the MBS analyst, and the shift leads on duty during shift B had maintained a regular night schedule since at least July 23.

¹²⁷ These times are expressed in eastern daylight time for the report; 8:00 a.m. and 8:00 p.m. eastern daylight time are 6:00 a.m. and 6:00 p.m. local Edmonton time, respectively.

Thus, with the exception of MBS analyst A, who had been off duty the 4 days before the accident, all of the Line 6B control center operators, MBS analysts, and shift leads had maintained regular work schedules for at least the 2 days or nights prior to the accident. However, detailed information regarding their actual sleep and wake times, as well as non-work activities, was not available.

2.7 Pipeline Public Awareness

Firefighters were dispatched to investigate an outdoor odor in response to a 911 call received on the evening of July 25. The caller to 911 said that there was a strong odor of either natural gas or crude oil near the airport along 17 Mile Road. Firefighters searched the area with combustible gas indicators and examined nearby industrial business areas and two natural gas facilities on Division Drive. The firefighters were unfamiliar with the odors associated with crude oil and were unable to identify the source. Over the course of the 14 hours following the first call to report the outdoor odor, seven more calls to 911 reported strong natural gas or petroleum odors in the same area. The 911 operators repeatedly informed the callers that the fire department had been dispatched to investigate the issue, but the 911 operators did not contact the pipeline operator or advise the public of health and safety risks. The 911 operators never dispatched the fire department in response to the subsequent calls even though these calls occurred over several hours, indicating an ongoing problem. The actions of both the first responders and the 911 operators are consistent with a phenomenon known as confirmation bias,¹²⁸ in which decision makers search for evidence consistent with their theories or decisions, while discounting contradictory evidence. Although there was evidence available to the first responders that something other than natural gas was causing noticeable odors in the Marshall area, they discounted that evidence, largely because it contradicted their own findings of no natural gas in the area. Similarly, the 911 operators, with the evidence from the first responders of no natural gas in the area, discounted subsequent calls regarding the strong odors in the Marshall area. Those calls were inconsistent with their own views that the problem causing the odors was either nonexistent or had been resolved. Although Enbridge had provided training to emergency responders in the Marshall area in February 2010, the firefighters' actions showed a lack of awareness of the nearby crude oil pipeline: they did not search along the Line 6B right-of-way, and they did not call Enbridge. The NTSB concludes that had the firefighters discovered the ruptured segment of Line 6B and called Enbridge, the two startups of the pipeline might not have occurred and the additional volume might not have been pumped.

The NTSB reviewed Enbridge's PAP, which was intended to inform the affected public, emergency officials, and public officials about pipelines and facilitate their ability to recognize and respond to a pipeline rupture. Although RP 1162 requires operators to communicate with audiences every 1 to 3 years, Enbridge mailed its public awareness materials to all audiences annually. However, even with more frequent mailings, this accident showed that emergency officials and the public lacked actionable knowledge.

¹²⁸ R.S. Nickerson, "Confirmation Bias; A Ubiquitous Phenomenon in Many Guises," *Review of General Psychology*, vol. 2, no. 2, (1998), pp. 175-220.

Public knowledge of pipeline locations and the hazards associated with the materials transported is critical for successful recognition and reporting of releases, as well as the safe response to pipeline ruptures. The transportation of hazardous materials by pipeline is unlike hazardous materials transportation by railroad or highway because a pipeline is a permanent fixture. A pipeline presents a unique challenge to awareness because it is often buried. When pipeline releases occur, a properly educated public can be the first to recognize and report the emergency.

The NTSB found that Enbridge conducted annual informal assessments and participated in the PAPERS survey every 2 years. A review of the 2009 PAPERS survey responses showed that of those who responded only 23 percent of the affected public and 47 percent of emergency officials responded that they were “very well informed” about pipelines in their community. Although the Enbridge program plan stated that effectiveness reviews were to be conducted, no specific guidelines or measurements for the evaluations were defined. Enbridge’s failure to have a process for using these survey results for improvements demonstrated a lack of commitment to improving the quality of its program. Therefore, the NTSB concludes that Enbridge’s review of its PAP was ineffective in identifying and correcting deficiencies. The NTSB further concludes that had Enbridge operated an effective PAP, local emergency response agencies would have been better prepared to respond to early indications of the rupture and may have been able to locate the crude oil and notify Enbridge before control center staff tried to start the line.

In May 2011, Enbridge revised its public awareness plan and created a public awareness committee that includes a performance metrics subcommittee. According to the committee charter, the committee meets four times a year and is responsible for an annual review of the PAP and the program performance measures.

In July 2011, PHMSA conducted an audit of Enbridge’s PAP. PHMSA identified several deficiencies in Enbridge’s program evaluation and effectiveness reviews and required that Enbridge correct the deficiencies.

Although Enbridge and PHMSA have taken these actions, the NTSB is concerned that pipeline operators do not provide emergency officials with specific information about their pipeline systems. The brochures that Enbridge mailed did not identify its pipeline’s location. Instead, the brochures directed the audiences to pipeline markers and to PHMSA’s National Pipeline Mapping System. In the NTSB’s 2011 report of the natural gas transmission pipeline rupture and fire in San Bruno, California, the NTSB made the following safety recommendation to PHMSA:

Require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to provide system-specific information about their pipeline systems to the emergency response agencies of the communities and jurisdictions in which those pipelines are located. This information should include pipe diameter, operating pressure, product transported, and potential impact radius. (P-11-8)

In its response letter to the NTSB, PHMSA stated that it had an emergency responder forum to identify pipeline emergencies for which emergency responders need to know how to

adequately prepare and respond. This safety recommendation was classified “Open—Acceptable Response.” Although PHMSA has held the emergency responder forum, no rulemaking has been initiated. Therefore, the NTSB reiterates Safety Recommendation P-11-8 to PHMSA. Because system-specific pipeline information is critical to the safe response to pipeline incidents, the NTSB is also concerned about the emergency officials’ lack of awareness of Enbridge’s pipeline. Therefore, the NTSB recommends that the International Association of Fire Chiefs and the National Emergency Number Association inform their members about the circumstances of the Marshall, Michigan, pipeline accident and urge their members to aggressively and diligently gather from pipeline operators system-specific information about the pipeline systems in their communities and jurisdictions.

2.8 Environmental Response

2.8.1 Effectiveness of the Emergency Response to this Accident

First responders’ initial containment efforts and tactics proved ineffective in preventing substantial quantities of oil from spreading and traveling miles downstream of the rupture. Enbridge’s first responders arrived on the scene just as oil was reaching the Kalamazoo River. Much of Enbridge’s initial efforts were concerned with the placement of oil containment measures downriver of the advancing oil sheen. These oil containment measures were placed many miles from the release site; these measures could have been put to better use on Talmadge Creek, which was much closer to the release.¹²⁹ Minimizing the release of oil from the source area would have reduced both the exposure risk to citizens living downriver and the severity of the environmental pollution resulting from this accident. The large volume of oil that escaped the source area also contributed greatly to the estimated \$767 million cleanup for this accident. Nearly 2 years after the accident, crews are still removing submerged oil and contaminated soils miles from the release site.

During interviews, first responders said that they were unaware of the scale of the oil release; this lack of knowledge contributed to their poor decision-making. The Enbridge crossing coordinator, whose crew of four individuals served as the entire team involved in Enbridge’s first response effort, told NTSB investigators that the first action the crew took upon locating the pipeline rupture site was to travel about 0.25 mile north to the Division Drive crossing where fire trucks were stationed. The crossing coordinator saw a large amount of oil flowing on the water and decided to follow the creek downstream about 1 to 1 1/2 miles to find the point where there was no oil and to install first containment measures there. He said the crew saw a very light oil sheen beginning as they placed sorbent boom across the swiftly flowing stream in an attempt to funnel oil to a collection point for a vacuum truck. Describing his rationale for installing the sorbent boom downriver, he told NTSB investigators that the crew at that time had no idea how much oil was released or whether oil would ultimately discharge that far downstream, and he suggested that the sorbent booming was a token effort given the few responders that were available on scene and the response time for additional personnel.

¹²⁹ *Characteristics of Response Strategies: A Guide for Spill Response Planning in Marine Environments.*

About 1 hour after the crossing coordinator confirmed the oil spill, the first arriving PLM supervisor from Bay City, who acted as the interim Enbridge incident commander, also observed the thickly oiled creek at Division Drive. Although the supervisor was aware that the bulk of the oil was still upstream near the source area and he observed oil actively flowing through the unprotected culvert, he nonetheless focused all of his attention on placement of the majority of oil spill response resources about 8.9 miles downstream on the Kalamazoo River ahead of the discharge at Heritage Park.

The decision to ignore the pool of oil upstream of the Division Drive culvert in favor of placing containment measures much farther downstream demonstrates a lack of awareness and knowledge of the dynamics and consequences of major oil releases and the need for more training. Although the first responders did not have the NRC's estimate of the amount of released oil during the initial phase of the response, they observed heavy amounts of oil flowing through the culvert pipe. Rather than attempting to stop the oil at the culvert pipe, which was within 0.25 mile of the source, they decided instead to try to stop the oil at the leading edge of the spill downstream.

The first responders were not alone in failing to recognize better opportunities to contain the oil spill. The Federal, state, and local response personnel, and the Enbridge supervisors, who arrived later, observed heavy amounts of oil discharging into the creek, yet, building a more effective underflow containment dam near the source area was the last strategy attempted on the first day of the response. The Bay City PLM supervisor who acted as the interim Enbridge incident commander told NTSB investigators that under normal weather conditions, he would have ordered the Division Drive culvert pipe completely plugged with earth; however, he considered the flow of water to be too great to attempt this action. An underflow dam at the culvert pipe would have solved this problem by facilitating a continuous flow of water while at the same time retaining much of the oil.

Regardless of the recent rainfall, opportunities to reduce the downstream impact of the oil spill were missed. Even if the volume of oil released was unknown, a more effective approach to mitigating the effects of the oil spill with limited resources would have been to focus on containing the bulk of the oil as close to the point of release as possible.¹³⁰ As a primary response, attempting to contain the advancing oil sheen miles downstream of the pipeline rupture site—while enormous quantities of oil were flowing through culvert pipes near the source area—was not an effective strategy. According to Enbridge's facility response plan, source containment should have been the primary concern of first responders. An operating-and-maintenance procedure referenced in the plan states that an attempt must be made to confine the product as close to the release source as possible to prevent it from entering a major river.

During the 10 years prior to this accident, Enbridge had participated in 2 of the 26 government-initiated oil spill response drills (in 2003 and 2004) under the National Preparedness for Response Exercise Program. PHMSA also participated in these two drills. Although the program requires pipeline operators to participate in at least one

¹³⁰ *Region 5 Regional Contingency Plan/Area Contingency Plan*, Section 3.2 Discharge/Release Control (U.S. Environmental Protection Agency and U.S. Coast Guard, November 2009).

government-initiated drill within a 36-month period, PHMSA has not frequently conducted exercises even though it has committed to conducting not more than 20 unannounced government-initiated exercises annually. Key Enbridge personnel who participated as first responders during the Marshall accident had received training that focused on oil-boom deployment and boat-handling for responses in large rivers and creeks. The training did not sufficiently address techniques that are appropriate for wetland environments, high water, or small creeks with swift moving water.

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

Workers with spill response duties need to be adequately trained to deploy and operate equipment they will actually use in a response and must be able to demonstrate knowledge of procedures for mitigating or preventing an oil discharge.¹³¹ Therefore, the NTSB recommends that Enbridge provide additional training to first responders to ensure that they (1) are aware of the best response practices and the potential consequences of oil releases and (2) receive practical training in the use of appropriate oil-containment and -recovery methods for all potential environmental conditions in the response zones.

Enbridge crews primarily deployed sorbent booms in the fast-flowing Talmadge Creek, which, according to industry and Federal guidance, is an ineffective method of containing oil except in stagnant waters. Sorbent booms are generally used for small spills or as a polishing technique to capture sheen escaping from skirted oil booms, not as a principal containment method for a large release. Had more effective containment measures been placed at strategic locations along Talmadge Creek—such as installing plywood sheet underflow dams over the seven culvert pipe stream crossings located between the release site and the Kalamazoo River—less oil might have entered the Kalamazoo River. NTSB investigators observed that the equipment used to construct underflow structures was not part of Enbridge's response equipment inventory. By chance, several pieces of surplus pipe and earth-moving equipment, which had been stored at the Marshall PLM shop for another purpose, were available for constructing an earthen underflow dam in the source area. Installing the first earthen underflow dam was a difficult and slow process that took all afternoon to complete. Nevertheless, first responders told NTSB investigators that using underflow dams was one of the major successes in the response to this accident.

Underflow dams constructed of plywood or other suitable material are easily and quickly installed over culvert pipe and would have been a more effective containment strategy to minimize the consequences of the release. The Bay City PLM supervisor recognized in retrospect that blocking the culvert pipes would likely have proven effective. An EPA training exercise held just 2 years earlier in Wood River, Nebraska, involved EPA personnel who

¹³¹ *Training Reference for Oil Spill Response* (U.S. Department of Transportation, U.S. Environmental Protection Agency, U.S. Department of the Interior, joint publication, August, 1994).

observed the deployment of culvert underflow structures.¹³² The NTSB postaccident photograph of the interior of the culvert pipe at Division Drive shows a thick black band of oil stain several inches thick about one-third the height of the pipe, which suggests that conditions would have been ideal to install an underflow dam at that location.

Although culvert pipe underflow dams are recognized as an effective method in these conditions, no emergency responders took the initiative to implement this method. Instead, crews attempted to contain oil in front of the culverts with skirted oil boom backed up with sorbent boom, even after creek water levels had returned to normal. By then, the water level was too shallow for skirted oil containment boom to be effective. The skirted oil booms that Enbridge had available on its spill response trailers are more suitable for open water response in slow flowing and deeper rivers and are less effective in small streams like Talmadge Creek.¹³³ Even the Enbridge facility response plan acknowledges that the use of booms is ineffective in fast current, shallow water, and steep bank environments. Nonetheless, Enbridge first responders were not provided with tools to construct underflow dams or with alternative oil containment methods appropriate for the environmental conditions that existed on the day of this accident.

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

Enbridge PLM supervisors stated that, as a result of this accident, they have recognized the value of having supplies on hand that are not necessarily immediately available elsewhere during an emergency. Such supplies might include corrugated metal pipe, plastic pipe, plywood, and stone for constructing underflow dams. The environment surrounding each segment of pipeline may present different challenges for containing oil in the event of an accident. A thorough assessment of potential oil release routes in conjunction with applicable best practices should help to identify equipment needs for those areas.

Therefore, the NTSB recommends that Enbridge review and update its oil pipeline emergency response procedures and equipment resources to ensure that appropriate containment equipment and methods are available to respond to all environments and at all locations along the pipeline to minimize the spread of oil from a pipeline rupture.

2.8.2 Facility Response Planning

A facility response plan is supposed to help the pipeline operator develop a response organization and ensure the availability of resources needed to respond to an oil release. The plan should also identify the response resources that are available in a timely manner, thereby reducing the severity and impact of the discharge.

¹³² *Shallow Water Spill Containment and Boom Deployment Training (A Case Study), Platte River Whooping Crane Maintenance Trust, Wood River, Nebraska* (U.S. Environmental Protection Agency Region 7) August 27–28, 2008 <<http://www.epa.gov/oem/docs/oil/fss/fss09/campbell.pdf>>.

¹³³ *Oil Spill Response in Fast Moving Currents, a Field Guide* (Groton, Connecticut: U.S. Coast Guard Research and Development Center, October 2001.)

2.8.2.1 Regulatory Requirements for Facility Response Planning

Title 49 CFR 194.115 requires pipeline operators to identify response resources and ensure that, either by a contract or other approved means, these resources will be available to mitigate a worst-case discharge under the three-tier response criteria. The regulation stops short of providing specific guidance for the amount of resources that must arrive at the scene of a discharge. In its February 23, 2005, final rule on response plans for onshore transportation-related pipelines, PHMSA stated it does not believe that it is necessary to specify the amount of response resources; PHMSA allows operators to determine the amount and to demonstrate that sufficient response resources are provided for their facility response plans.¹³⁴ Consequently, pipeline operators are left with vague three-tier response criteria that allow them to subjectively define what resources are adequate and that provide no measure for regulators to evaluate the sufficiency of spill response planning.

Enbridge has chosen to interpret the Tier 1 requirement as meaning the company resources that are stationed at the local PLM facility, while Tier 2 refers to the company resources throughout the company's Chicago region. The amount of company-owned response resources provided in the facility response plan is not identified with any basis in capability to recover a particular quantity of discharge. According to Enbridge's interpretation of the regulation, its Tier 3 resources, which consisted of two contracted oil spill response organizations that are identified as Coast Guard-classified oil spill removal organizations¹³⁵ for response to a worst-case discharge, would not be deployed to the scene until 60 hours after a discharge. Other pipeline operators may have any number of different interpretations of what constitutes resources necessary to remove a worst-case discharge.

The current PHMSA facility response planning regulation allows operators to interpret the requirements, rendering it improbable that PHMSA would be able to perform an adequate review of facility response plans or enforce Federal requirements that pipeline operators identify and ensure that adequate response resources are available to respond to worst-case discharges. In contrast, regulatory requirements for oil spill response capability planning that are administered by the Coast Guard¹³⁶ and by the EPA¹³⁷ provide specific response capability standards. For instance, both the Coast Guard and EPA regulations provide a matrix for identifying necessary resources for facility response planning. These regulations require that resources identified in the response plan for meeting the applicable worst-case discharge planning volume must be located such that they can arrive on scene within the times specified for the applicable response planning tiers. Had the Enbridge pipeline facilities been subject to the EPA or Coast Guard regulations, the company would have been required to plan for an on-water recovery of a worst-case discharge by ensuring the availability of the resources shown in table 7.

¹³⁴ *Federal Register*, vol. 70, no. 35 (February 23, 2005), p. 8734.

¹³⁵ The Coast Guard created the voluntary oil spill removal organization classification program so that plan holders could list oil spill removal organizations in response plans in lieu of providing extensive detailed lists of response resources if the organization has been classified by the Coast Guard and its capacity has been determined to equal or exceed the response capability needed by the plan holder.

¹³⁶ Title 33 CFR Part 154, Appendix C.

¹³⁷ Title 40 CFR Part 112, Appendix E.

Table 7. Response resources for on-water recovery that Enbridge would have been required to identify in its facility response plan and have available by contract or other means, had its facilities been regulated by the Coast Guard or the EPA.

| | Tier 1 | Tier 2 | Tier 3 |
|---|---------------------|----------|----------|
| Time | 12 hours | 36 hours | 60 hours |
| Effective daily recovery capacity (gallons/day) | 78,750 ^a | 119,994 | 180,012 |

^a For river and canal operating environments, Appendix C caps the Tier 1 response capability at 78,750 gallons per day.

To determine whether an operator has sufficient equipment capacity identified in its facility response plan to meet the applicable planning criteria listed in table 5, the Coast Guard and EPA regulations require operators to report oil recovery equipment by manufacturer, model, and effective daily recovery capacity.¹³⁸ Although pipeline facilities are not required to conduct any similar exercise to determine the capacity of their resources to recover oil, PHMSA references Coast Guard regulations at 33 CFR Part 154, Appendix C and other regulatory agency sources of nonmandatory guidance to assist operators in preparing response plans. No indication exists in the Enbridge response plan that the company utilized any such guidance. The NTSB concludes that PHMSA’s regulatory requirements for response capability planning do not ensure a high level of preparedness equivalent to the more stringent requirements of the Coast Guard and the EPA.

When accidents occur, the risk of environmental damage can be greater for pipelines than for fixed facilities and shipping terminals because pipelines can travel for hundreds of miles and response resources may be required at locations that are difficult to predict and can be hard to reach. Nonetheless, the Oil Pollution Act of 1990 mandates an equivalent level of response for all facilities and vessels that handle oil and petroleum products: the capability to remove a worst-case discharge to the maximum extent practicable and to mitigate or prevent a substantial threat of a worst-case discharge. PHMSA’s regulations for oil pipeline response planning are clearly inferior when compared to similar Coast Guard and EPA requirements.

The NTSB concludes that without specific Federal spill response preparedness standards, pipeline operators do not have response planning guidance for a worst-case discharge.

Because the current PHMSA regulation provides no assurance that oil pipeline operators will develop adequate facility response plans to provide for response to worst-case discharges, the NTSB recommends that PHMSA amend 49 CFR Part 194 to harmonize onshore oil pipeline response planning requirements with those of the Coast Guard and the EPA for facilities that handle and transport oil and petroleum products to ensure that pipeline operators have adequate resources available to respond to worst-case discharges.

¹³⁸ Coast Guard and EPA regulations provide a formula for calculating effective daily recovery capacity that considers potential limitations of oil recovery equipment due to available daylight, weather, sea state, and percentage of emulsified oil in the recovered material.

Until specific response planning requirements are included in 49 CFR Part 194, the NTSB recommends that PHMSA issue an advisory bulletin to notify pipeline operators (1) of the circumstances of the Marshall, Michigan, pipeline accident, and (2) of the need to identify deficiencies in facility response plans and to update these plans as necessary to conform with the nonmandatory guidance for determining and evaluating required response resources as provided in Appendix A of 49 CFR Part 194, “Guidelines for the Preparation of Response Plans.”

2.8.2.2 Adequacy of Enbridge Facility Response Plan

Enbridge stated that it relied on company-owned resources for Tier 1 and Tier 2 responses. The facility response plan did not provide any description of the effective daily recovery capability of the response equipment in Enbridge’s inventory, leaving a plan reviewer unable to determine whether the equipment was adequate for the job. Under both Coast Guard and EPA regulations, Enbridge would have been required to quantify its equipment recovery capacities to determine whether they were adequate against the three-tier planning criteria. It is doubtful that the recovery equipment identified in Enbridge’s facility response plan would have been sufficient to satisfy the requirements of either the Tier 1 or the Tier 2 level of Coast Guard and EPA oil spill response regulations.

The EPA reported that Enbridge did not have adequate resources on site to deal with the magnitude of the spill and experienced significant difficulty locating necessary resources. The facility response plan identified two oil spill response organizations, but neither organization had the capability to respond to Marshall, Michigan, in a timely manner. More than 4 hours after it became aware of the oil release, Enbridge first contacted Bay West, which launched its resources to Marshall more than 5 hours after notification. Bay West finally arrived on scene on July 27, after a 10- to 11-hour drive. The other oil spill response organization, Garner Environmental Services, Inc. arrived on scene on July 29, 3 days after the spill was reported. By then, it was too late for either spill response contractor to mitigate the spread of the oil release.

The EPA also reported that available local contractors were not used until the EPA provided the contact information for local contractors who could respond quickly. Once on scene, the Bay City PLM supervisor spent considerable time calling local contractors not identified in the facility response plan. In addition, the facility response plan did not indicate that prior agreements were in place to ensure that contractors other than Bay West and Garner Environmental Services, Inc. had crews and equipment available during an emergency.

In accordance with 49 CFR 194.115(a),¹³⁹ pipeline operating companies and response contractors or organizations must have a contract or an agreement to identify and ensure the availability of specified personnel and equipment within stipulated response times for a specified geographic area. Enbridge should have been prepared with local resources on standby to respond to an accident because Bay West and Garner Environmental Services, Inc. had told Enbridge that they would be unable to respond quickly unless they could use local contractors. If the facility response plan had identified sufficient contractor resources near Marshall, Michigan, and these

¹³⁹ Title 49 CFR 194.115(a) states, “Each operator shall identify and ensure, by contract or other approved means, the resources necessary to remove, to the maximum extent practicable, a worst case discharge and to mitigate or prevent a substantial threat of a worst case discharge.”

contractor resources had been under contract, the response to the oil spill would have been more timely and, therefore, more effective.

Further, the equipment identified by Enbridge's facility response plan was more suited to ideal weather conditions than to the river conditions that existed in this accident. No provisions existed for equipment to construct underflow dams, which were the most effective means of containment in this accident.¹⁴⁰

In summary, the spill response was hampered by inadequate resources on site; lack of spill response organizations under contract near Marshall, Michigan; and use of spill response equipment that was not appropriate for the environment and weather conditions. These deficiencies were all a result of poor response planning.

PHMSA issued its June 23, 2010, facility response plan advisory bulletin to notify pipeline companies of the need to review and update their plans to ensure adequate resources are available to comply with emergency response requirements. Enbridge responded that, 5 days before the Marshall accident, it had concluded that its plan was complete and appropriate for responding to a worst-case discharge. However, Enbridge's actions following the discovery of the oil in Marshall revealed that the plan had not considered all possible operating environments and appropriate response methods. PHMSA stated that it plans to include a review of lessons learned when it reviews the Enbridge facility response plan due for renewal in 2015 or when Enbridge next amends its plan.

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

Therefore, the NTSB recommends that Enbridge update its facility response plan to identify adequate resources to respond to and mitigate a worst-case discharge for all weather conditions and for all its pipeline locations before the required resubmittal in 2015.

2.8.2.3 PHMSA Oversight of Facility Response Plans

PHMSA has a small staff to review and oversee facility response plans when compared to other agencies that review plans that are required under the Oil Pollution Act of 1990. PHMSA receives on average about two facility response plans per week to review for renewal.¹⁴¹ PHMSA has 1.5 full-time employees managing about 450 response plans, which is far fewer than EPA Region 6, which has 27 employees and contractors reviewing 1,700 plans, or the Coast Guard Sector Boston, which assigns 7 or 8 inspectors and trainees to review 45 plans. Therefore, PHMSA has dedicated significantly fewer resources to facility response plan review as compared to other Federal agencies, which calls into question PHMSA's ability to conduct adequate assessments.

¹⁴⁰ As noted earlier, crews found surplus pipe and equipment and took the initiative to construct underflow dams, although too late, to contain much of the oil that was released.

¹⁴¹ A Volpe draft report indicates that 450 pipeline facility response plans must be reviewed and renewed every 5 years. PHMSA's website at <<http://phmsa.dot.gov/pipeline/initiatives/opa>> reports that 1,500 facility response plans have been submitted to PHMSA.

Within 2 weeks of receiving the Enbridge facility response plan, PHMSA had approved it. With this short turnaround time, only a cursory review of the plan was likely conducted. Because no specific regulatory guidance exists to measure the adequacy of the plan for response capability, it could be approved only based on the judgment of PHMSA staff. The review of the Enbridge facility response plan included a company-submitted, 16-element self-assessment affirming the adequacy of the plan. PHMSA's environmental planning officer was assigned to review the questionnaire and the facility response plan to determine whether it met appropriate regulatory requirements. The environmental planning officer approved the plan without requiring supplemental information or citing any deficiencies in the plan.

Essentially, the regulations allow the pipeline industry to dictate the requirements of an adequate spill response and to determine whether those requirements have been met. The NTSB noted that there were no metrics for what was required within a tier and no such activities were identified in the plan. Further, neither the regulations nor the plan defined what constitutes "enough trained personnel."

PHMSA did not perform on-site audits to verify the content and adequacy of plans before approving them. In contrast, both the Coast Guard and the EPA conduct on-site audits and plan reviews after the initial review and approval of the submitted plan.

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

The Oil Spill Liability Trust Fund, create by Congress in 1986, is currently funded to \$1 billion from sources such as the Barrel Tax,¹⁴² transfers from other pollution funds, cost recoveries, and penalty collection. PHMSA and other Federal agencies receive annual appropriations to cover administrative, operational, personnel, enforcement, and research and development costs related to Oil Pollution Act activities. Such activities include regulation and enforcement of facility operations and response planning and cooperative relationships with oil industry stakeholders, which include periodic drills and implementation of changes to national and area contingency plans.

At the time of this accident, PHMSA received an \$18.9 million appropriation annually¹⁴³ from the Oil Spill Liability Trust Fund for various expenses necessary to conduct the functions of its pipeline safety program, including the facility response planning preparedness program, which consists of 1.5 full-time positions. In 2008, PHMSA received about \$1.5 million more from the fund than the EPA,¹⁴⁴ yet the EPA operates a significantly more robust facility response plan program that includes on-site audits and exercises.

¹⁴² Section 405(a) of the Energy Improvement and Extension Act of 2008, Public Law 110-343, div. B, extended the per-barrel excise tax of \$0.08 a barrel for petroleum products produced or imported into the United States through 2017.

¹⁴³ *Pipeline and Hazardous Materials Safety Administration Budget Estimates, Fiscal Year 2012*, p. 50.

¹⁴⁴ *Oil Spill Liability Trust Fund Annual Report Fiscal Year 2004–Fiscal Year 2008*, National Pollution Funds Center, U.S. Department of Homeland Security, U.S. Coast Guard.

Therefore, the NTSB recommends that the U.S. Secretary of Transportation audit PHMSA's onshore pipeline facility response plan program's business practices, including reviews of response plans and drill programs, and take appropriate action to correct deficiencies. The NTSB further recommends that the U.S. Secretary of Transportation allocate sufficient resources as necessary to ensure that PHMSA's onshore pipeline facility response plan program meets all of the requirements of the Oil Pollution Act of 1990.

2.9 Summary of Enbridge Organizational Deficiencies

To evaluate the role of Enbridge in this accident, the NTSB's investigation focused primarily on the Line 6B operations before, during, and after the rupture. During the investigation, major deficiencies of the company emerged, as discussed in previous sections of this report. These deficiencies led to the rupture, exacerbated its results, and then failed to mitigate its effects. These deficiencies include the following:

- Enbridge's integrity management program had numerous deficiencies that resulted in Enbridge not repairing a detected feature on a pipeline susceptible to corrosion and cracking because of its failed coating.
- Enbridge's PAP failed to effectively inform the affected public, which included citizens and emergency response agencies, about the location of its pipeline, of the key indicators of unintended product releases from the pipeline, and how to report suspected product releases.
- Despite the availability of the information necessary for a correct interpretation, Enbridge's control center staff misinterpreted the rupture and started the pipeline twice during the 17 hours it took to identify the rupture.
- Enbridge's postaccident response failed to either slow or stop the flow of the released oil into a major waterway.

Although these deficiencies involved different elements of Enbridge's operations, and may appear unrelated, taken together they suggest a systemic deficiency in the company's approach to safety. Each of the following identified deficiencies, either individually or together, played a part in the accident:

- Enbridge's response to past integrity management related accidents focused only on the proximate cause, without a systematic examination of company actions, policies, and procedures that may have been involved.
- An integrity management program that, in the absence of clear regulatory guidelines, consistently chose a less-than-conservative approach to pipeline safety margins for crack features.
- A period of rapid growth in control center activities and personnel occurred without an objective assessment of the safety implications of the growth.
- A leak-detection process that was prone to misinterpretation and differing expectations of control center analysts and operators.

Taken together, the evidence suggests that the Marshall accident was the result not of isolated deficiencies in the company's integrity management system, its control center oversight, its PAP, or its postaccident emergency response activities, but rather of an approach to safety that did not adequately address the combined risks. By focusing on only the immediate cause of each incident, the company failed to look for and to determine patterns or underlying factors. Some of the underlying factors in this accident began many years earlier and converged with more recent changes only at the time of rupture.

Enbridge became increasingly tolerant of the procedural violations designed to minimize the adverse consequences of a rupture. Finally, Enbridge's emergency response to this accident was ineffective because it failed to stop hundreds of thousands of gallons of oil from entering the Kalamazoo River.

Enbridge insufficiently assessed pipeline defects for excavation and remediation to prevent flaws from becoming cracks that resulted in a rupture, inadequately prepared its control center staff to identify the ruptured pipeline, and inadequately prepared communities adjacent to pipelines to contain leaks that occurred in the lines. Enbridge also inadequately prepared its first responders to contain a major spill.

Therefore, the NTSB concludes that Enbridge's failure to exercise effective oversight of pipeline integrity and control center operations, implement an effective PAP, and implement an adequate postaccident response were organizational failures that resulted in the accident and increased its severity.

Although Enbridge met PHMSA regulations in its pipeline operations, the evidence indicates that the company had multiple opportunities to identify and to address safety hazards before this accident occurred, but it failed to do so. Even the response to a safety culture assessment conducted following the Clearbrook, Minnesota, accident in 2007,¹⁴⁵ which resulted in the creation of the position of director of safety culture, was insufficient. This director was tasked only with examining field safety of pipeline operations. Although Enbridge had implemented what it referred to as a health and safety management system, the system only partially met the standards of an SMS. For example, it addressed only on-site safety, not pipeline operations. Control center errors were identified as employee-caused and were not considered system deficiencies, contrary to SMS guidelines. Had the company implemented and maintained a comprehensive SMS, it would have focused not only on field operations safety, but also would have incorporated control center operations, pipeline integrity management, and postaccident response plans and a comprehensive continuous examination of the safety of pipeline operations.

Enbridge's safety program focused on the welfare of individuals in the work environment, but it did not consider the safety of operational processes, such as control center operations and integrity management. Previous accidents in other industries and transportation modes have revealed this organizational deficiency—that is, instituting safety programs that

¹⁴⁵ *Enbridge Energy Partners, L.P. 34"-Line No. 3, Milepost 912; Clearwater County, Minnesota, November 28, 2007, Accident Report*, prepared by the Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, Central Region Office and the Minnesota Department of Public Safety, Fire Marshall's Office, Office of Pipeline Safety. The NTSB delegated this accident investigation; the pipeline accident number is DCA-08-FP-003.

address only personal safety, not operational system safety. For example, in its investigation of the March 23, 2005, explosion and fire in a chemical refinery, which killed 15 people and injured 80, the U.S. Chemical Safety and Hazard Investigation Board noted that British Petroleum had focused on the personal safety of employees and not on the process safety of its operations. The investigation report¹⁴⁶ stated, “As personal injury safety statistics improved, [British Petroleum] Group executives stated that they thought safety performance was headed in the right direction. At the same time, process safety performance continued to decline at Texas City.”

Also, in its investigation of the June 22, 2009, collision of two Washington Metropolitan Area Transit Authority trains, where 9 people were killed and 52 injured, the NTSB observed a deficient organizational safety culture, stating in its report,¹⁴⁷ “The NTSB is concerned that [Washington Metropolitan Area Transit Authority] senior management may have placed too much emphasis on investigating events such as station and escalator injuries to the exclusion of passenger safety during transit.”

In recent years, several transportation modes have implemented SMSs to enhance the safety of their operations, and the NTSB has consistently supported these activities. The NTSB has advocated the implementation of SMSs in transportation systems by elevating SMSs to its Most Wanted List. However, the NTSB has not called for an SMS in pipeline operations. This Marshall accident and the 2010 pipeline accident in San Bruno, California, indicate that SMSs are needed to enhance the safety of pipeline operations.

Both the San Bruno accident and the Marshall accident involved errors at the management and operator levels in both pipeline integrity and control center operations. The delays in recognizing and responding to the pipeline rupture and the deficiencies in control center team performance were prominent aspects of both accidents.

SMSs continuously identify, address, and monitor threats to the safety of company operations by doing the following:

- Proactively addressing safety issues before they become incidents or accidents.
- Documenting safety procedures and requiring strict adherence to the procedures by safety personnel.
- Treating operator errors as system deficiencies and not as reasons to punish and intimidate operators.
- Requiring senior company management to commit to operational safety.
- Identifying personnel responsible for safety initiatives and oversight.
- Implementing a nonpunitive method for employees to report safety hazards.

¹⁴⁶ *Refinery Fire and Explosion, BP, Texas City, Texas, March 23, 2005*, Report No. 2005-04-I-TX (Washington, D.C.: U.S. Chemical Safety and Hazard Investigation Board, 2007), p. 144.

¹⁴⁷ *Collision of Two Washington Metropolitan Area Transit Authority Metrorail Trains Near Fort Totten Station, Washington, D.C., June 22, 2009*, Railroad Accident Report NTSB/RAR-10/02 (Washington, D.C.: National Transportation Safety Board, 2010).

- Continuously identifying and addressing risks in all safety-critical aspects of operations.
- Providing safety assurance by regularly evaluating (or auditing) operations to identify and address risks.

The evidence from this accident and from the San Bruno accident indicates that company oversight of pipeline control center management and operator performance was deficient. In both cases, pipeline ruptures were inadequately identified and delays in identifying and responding to the leaks exacerbated the consequences of the initial pipeline ruptures.

Therefore, the NTSB concludes that pipeline safety would be enhanced if pipeline companies implemented SMSs.

The API facilitates the development and maintenance of national consensus standards for the petroleum and petrochemical industry, including liquid and gas pipelines. In 1990, the API published API RP 750, *Management of Process Hazards*, which is an SMS for the refining and chemical industries.

Because of the improvements to safety that accrue from the use of a comprehensive SMS, the NTSB recommends that the API facilitate the development of an SMS standard specific to the pipeline industry that is similar in scope to the API's RP 750, *Management of Process Hazards*. The development should follow established American National Standards Institute requirements for standard development.

3 Conclusions

3.1 Findings

1. The following were not factors in this accident: cathodic protection, microbial corrosion, internal corrosion, transportation-induced metal fatigue, third-party damage, and pipe manufacturing defects.
2. Insufficient information was available from the postaccident alcohol testing; however, the postaccident drug testing showed that use of illegal drugs was not a factor in the accident.
3. The Line 6B segment ruptured under normal operating pressure due to corrosion fatigue cracks that grew and coalesced from multiple stress corrosion cracks, which had initiated in areas of external corrosion beneath the disbonded polyethylene tape coating.
4. Title 49 *Code of Federal Regulations* (CFR) 195.452(h) does not provide clear requirements regarding when to repair and when to remediate pipeline defects and inadequately defines the requirements for assessing the effect on pipeline integrity when either crack defects or cracks and corrosion are simultaneously present in the pipeline.
5. The Pipeline and Hazardous Materials Safety Administration (PHMSA) failed to pursue findings from previous inspections and did not require Enbridge Incorporated (Enbridge) to excavate pipe segments with injurious crack defects.
6. Enbridge's delayed reporting of the "discovery of condition" by more than 460 days indicates that Enbridge's interpretation of the current regulation delayed the repair of the pipeline.
7. Enbridge's integrity management program was inadequate because it did not consider the following: a sufficient margin of safety, appropriate wall thickness, tool tolerances, use of a continuous reassessment approach to incorporate lessons learned, the effects of corrosion on crack depth sizing, and accelerated crack growth rates due to corrosion fatigue on corroded pipe with a failed coating.
8. To improve pipeline safety, a uniform and systematic approach in evaluating data for various types of in-line inspection tools is necessary to determine the effect of the interaction of various threats to a pipeline.
9. Pipeline operators should not wait until PHMSA promulgates revisions to 49 CFR 195.452 before taking action to improve pipeline safety.
10. PII Pipeline Solutions' analysis of the 2005 in-line inspection data for the Line 6B segment that ruptured mischaracterized crack defects, which resulted in Enbridge not evaluating them as crack-field defects.

11. The ineffective performance of control center staff led them to misinterpret the rupture as a column separation, which led them to attempt two subsequent startups of the line.
12. Enbridge failed to train control center staff in team performance, thereby inadequately preparing the control center staff to perform effectively as a team when effective team performance was most needed.
13. Enbridge failed to ensure that all control center staff had adequate knowledge, skills, and abilities to recognize and address pipeline leaks, and their limited exposure to meaningful leak recognition training diminished their ability to correctly identify the cause of the Material Balance System (MBS) alarms.
14. The Enbridge control center and MBS procedures for leak detection alarms and identification did not fully address the potential for leaks during shutdown and startup, and Enbridge management did not prohibit control center staff from using unapproved procedures.
15. Enbridge's control center staff placed a greater emphasis on the MBS analyst's flawed interpretation of the leak detection system's alarms than it did on reliable indications of a leak, such as zero pressure, despite known limitations of the leak detection system.
16. Enbridge control center staff misinterpreted the absence of external notifications as evidence that Line 6B had not ruptured.
17. Although Enbridge had procedures that required a pipeline shutdown after 10 minutes of uncertain operational status, Enbridge control center staff had developed a culture that accepted not adhering to the procedures.
18. Enbridge's review of its public awareness program was ineffective in identifying and correcting deficiencies.
19. Had Enbridge operated an effective public awareness program, local emergency response agencies would have been better prepared to respond to early indications of the rupture and may have been able to locate the crude oil and notify Enbridge before control center staff tried to start the line.
20. Had the firefighters discovered the ruptured segment of Line 6B and called Enbridge, the two startups of the pipeline might not have occurred and the additional volume might not have been pumped.
21. Although Enbridge quickly isolated the ruptured segment of Line 6B after receiving a telephone call about the release, Enbridge's emergency response actions during the initial hours following the release were not sufficiently focused on source control and demonstrated a lack of awareness and training in the use of effective containment methods.
22. Had Enbridge implemented effective oil containment measures for fast-flowing waters, the amount of oil that reached Talmadge Creek and the Kalamazoo River could have been reduced.

23. PHMSA's regulatory requirements for response capability planning do not ensure a high level of preparedness equivalent to the more stringent requirements of the U.S. Coast Guard and the U.S. Environmental Protection Agency.
24. Without specific Federal spill response preparedness standards, pipeline operators do not have response planning guidance for a worst-case discharge.
25. The Enbridge facility response plan did not identify and ensure sufficient resources were available for the response to the pipeline release in this accident.
26. If PHMSA had dedicated the resources necessary and conducted a thorough review of the Enbridge facility response plan, it would have disapproved the plan because it did not adequately provide for response to a worst-case discharge.
27. Enbridge's failure to exercise effective oversight of pipeline integrity and control center operations, implement an effective public awareness program, and implement an adequate postaccident response were organizational failures that resulted in the accident and increased its severity.
28. Pipeline safety would be enhanced if pipeline companies implemented safety management systems.

3.2 Probable Cause

The National Transportation Safety Board (NTSB) determines that the probable cause of the pipeline rupture was corrosion fatigue cracks that grew and coalesced from crack and corrosion defects under disbonded polyethylene tape coating, producing a substantial crude oil release that went undetected by the control center for over 17 hours. The rupture and prolonged release were made possible by pervasive organizational failures at Enbridge Incorporated (Enbridge) that included the following:

- Deficient integrity management procedures, which allowed well-documented crack defects in corroded areas to propagate until the pipeline failed.
- Inadequate training of control center personnel, which allowed the rupture to remain undetected for 17 hours and through two startups of the pipeline.
- Insufficient public awareness and education, which allowed the release to continue for nearly 14 hours after the first notification of an odor to local emergency response agencies.

Contributing to the accident was the Pipeline and Hazardous Materials Safety Administration's (PHMSA) weak regulation for assessing and repairing crack indications, as well as PHMSA's ineffective oversight of pipeline integrity management programs, control center procedures, and public awareness.

Contributing to the severity of the environmental consequences were (1) Enbridge's failure to identify and ensure the availability of well-trained emergency responders with sufficient response resources, (2) PHMSA's lack of regulatory guidance for pipeline facility response planning, and (3) PHMSA's limited oversight of pipeline emergency preparedness that led to the approval of a deficient facility response plan.

4 Recommendations

4.1 New Recommendations

To the U.S. Secretary of Transportation:

Audit the Pipeline and Hazardous Materials Safety Administration's onshore pipeline facility response plan program's business practices, including reviews of response plans and drill programs, and take appropriate action to correct deficiencies. (P-12-1)

Allocate sufficient resources as necessary to ensure that the Pipeline and Hazardous Materials Safety Administration's onshore pipeline facility response plan program meets all of the requirements of the Oil Pollution Act of 1990. (P-12-2)

To the Pipeline and Hazardous Materials Safety Administration:

Revise Title 49 *Code of Federal Regulations* 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 stress corrosion cracking as applicable. (P-12-3)

Revise Title 49 *Code of Federal Regulations* 195.452(h)(2), the "discovery of condition," to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify the Pipeline and Hazardous Materials Safety Administration and provide an expected date when adequate information will become available. (P-12-4)

Conduct a comprehensive inspection of Enbridge Incorporated's integrity management program after it is revised in accordance with Safety Recommendation P-12-11. (P-12-5)

Issue an advisory bulletin to all hazardous liquid and natural gas pipeline operators describing the circumstances of the accident in Marshall, Michigan—including the deficiencies observed in Enbridge Incorporated's integrity management program—and ask them to take appropriate action to eliminate similar deficiencies. (P-12-6)

Develop requirements for team training of control center staff involved in pipeline operations similar to those used in other transportation modes. (P-12-7)

Extend operator qualification requirements in Title 49 *Code of Federal Regulations* Part 195 Subpart G to all hazardous liquid and gas transmission control center staff involved in pipeline operational decisions. (P-12-8)

Amend Title 49 *Code of Federal Regulations* Part 194 to harmonize onshore oil pipeline response planning requirements with those of the U.S. Coast Guard and the U.S. Environmental Protection Agency for facilities that handle and transport oil and petroleum products to ensure that pipeline operators have adequate resources available to respond to worst-case discharges. (P-12-9)

Issue an advisory bulletin to notify pipeline operators (1) of the circumstances of the Marshall, Michigan, pipeline accident, and (2) of the need to identify deficiencies in facility response plans and to update these plans as necessary to conform with the nonmandatory guidance for determining and evaluating required response resources as provided in Appendix A of Title 49 *Code of Federal Regulations* Part 194, "Guidelines for the Preparation of Response Plans." (P-12-10)

To Enbridge Incorporated:

Revise your integrity management program to ensure the integrity of your hazardous liquid pipelines as follows: (1) implement, as part of the excavation selection process, a safety margin that conservatively takes into account the uncertainties associated with the sizing of crack defects from in-line inspections; (2) implement procedures that apply a continuous reassessment approach to immediately incorporate any new relevant information as it becomes available and reevaluate the integrity of all pipelines within the program; (3) develop and implement a methodology that includes local corrosion wall loss in addition to the crack depth when performing engineering assessments of crack defects coincident with areas of corrosion; and (4) develop and implement a corrosion fatigue model for pipelines under cyclic loading that estimates growth rates for cracks that coincide with areas of corrosion when determining reinspection intervals. (P-12-11)

Establish a program to train control center staff as teams, semiannually, in the recognition of and response to emergency and unexpected conditions that includes supervisory control and data acquisition system indications and Material Balance System software. (P-12-12)

Incorporate changes to your leak detection processes to ensure that accurate leak detection coverage is maintained during transient operations, including pipeline shutdown, pipeline startup, and column separation. (P-12-13)

Provide additional training to first responders to ensure that they (1) are aware of the best response practices and the potential consequences of oil releases and (2) receive practical training in the use of appropriate oil-containment and -recovery methods for all potential environmental conditions in the response zones. (P-12-14)

Review and update your oil pipeline emergency response procedures and equipment resources to ensure that appropriate containment equipment and methods are available to respond to all environments and at all locations along the pipeline to minimize the spread of oil from a pipeline rupture. (P-12-15)

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

To the American Petroleum Institute:

Facilitate the development of a safety management system standard specific to the pipeline industry that is similar in scope to your Recommended Practice 750, *Management of Process Hazards*. The development should follow established American National Standards Institute requirements for standard development. (P-12-17)

To the Pipeline Research Council International:

Conduct a review of various in-line inspection tools and technologies—including, but not limited to, tool tolerance, the probability of detection, and the probability of identification—and provide a model with detailed step-by-step procedures to pipeline operators for evaluating the effect of interacting corrosion and crack threats on the integrity of pipelines. (P-12-18)

To the International Association of Fire Chiefs and the National Emergency Number Association:

Inform your members about the circumstances of the Marshall, Michigan, pipeline accident and urge your members to aggressively and diligently gather from pipeline operators system-specific information about the pipeline systems in their communities and jurisdictions. (P-12-19)

4.2 Reiterated Recommendation

As a result of this accident investigation, the National Transportation Safety Board reiterates the following previously issued safety recommendation:

Require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to provide system-specific information about their pipeline systems to the emergency response agencies of the communities and

jurisdictions in which those pipelines are located. This information should include pipe diameter, operating pressure, product transported, and potential impact radius. (P-11-8)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

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Adopted: July 10, 2012

5 Appendixes

5.1 Appendix A: Investigation

The National Response Center was notified about the Enbridge Incorporated (Enbridge) Line 6B rupture and release of crude oil in Marshall, Michigan, on July 26, 2010, at 1:33 p.m. The Pipeline and Hazardous Materials Safety Administration (PHMSA) notified the National Transportation Safety Board (NTSB) about the accident about 8:30 a.m., eastern daylight time, on July 27, 2010. The investigator-in-charge and other investigative team members were launched from the NTSB's Washington, D.C., headquarters office to Marshall, Michigan; another investigator was launched to the Enbridge control center in Edmonton, Alberta, Canada. Due to the severity of the accident, additional investigators were sent to Marshall from headquarters; another team member was launched from Jacksonville, Florida, to assist with the environmental response investigation. Chairman Deborah A.P. Hersman was the Board Member on scene. Investigative groups were formed to study integrity management, materials, control center operations, environmental response, emergency response, and human performance issues.

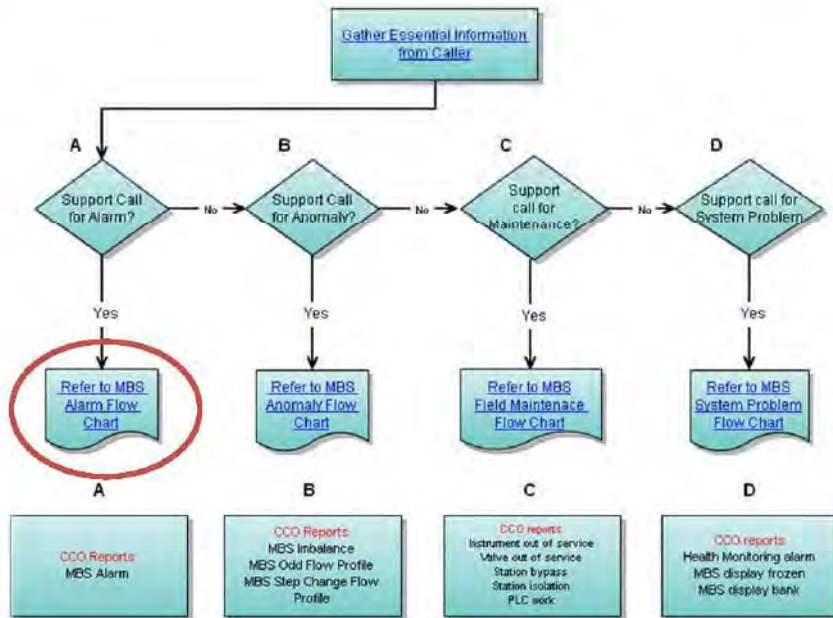
Parties to the investigation were PHMSA, Enbridge, PII Pipeline Solutions, and the U.S. Environmental Protection Agency.

5.2 Appendix B: Enbridge's MBS and Control Center Operations Procedures

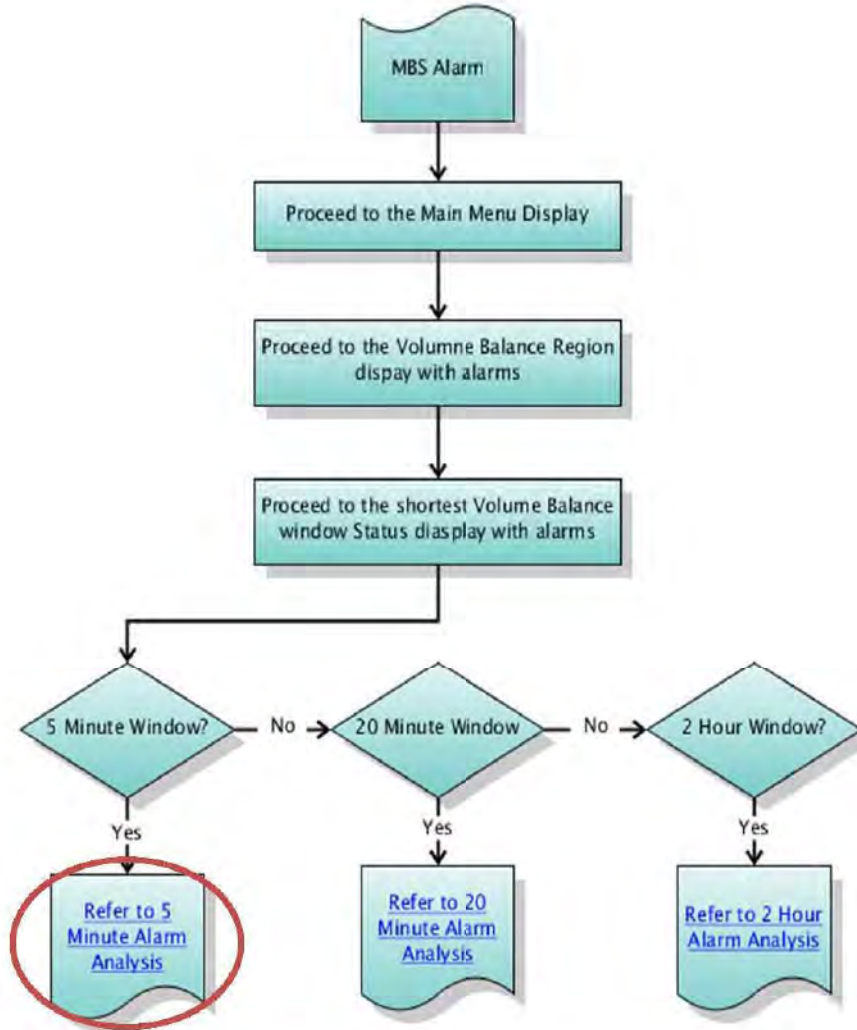
MBS Procedure for Examining MBS Alarms

Enbridge Responses to IR No. 108
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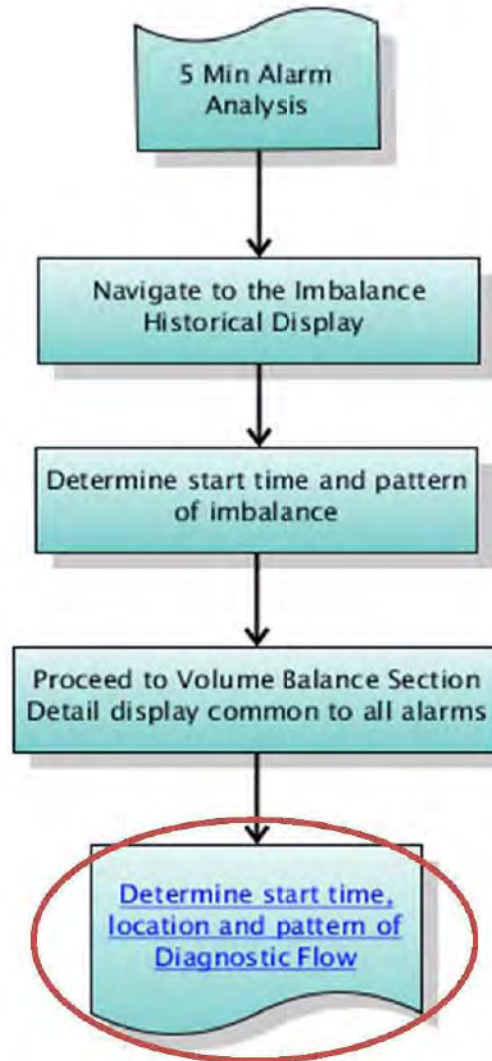
1) Using the flow chart to respond to a 5-min MBS alarm related to column separation.



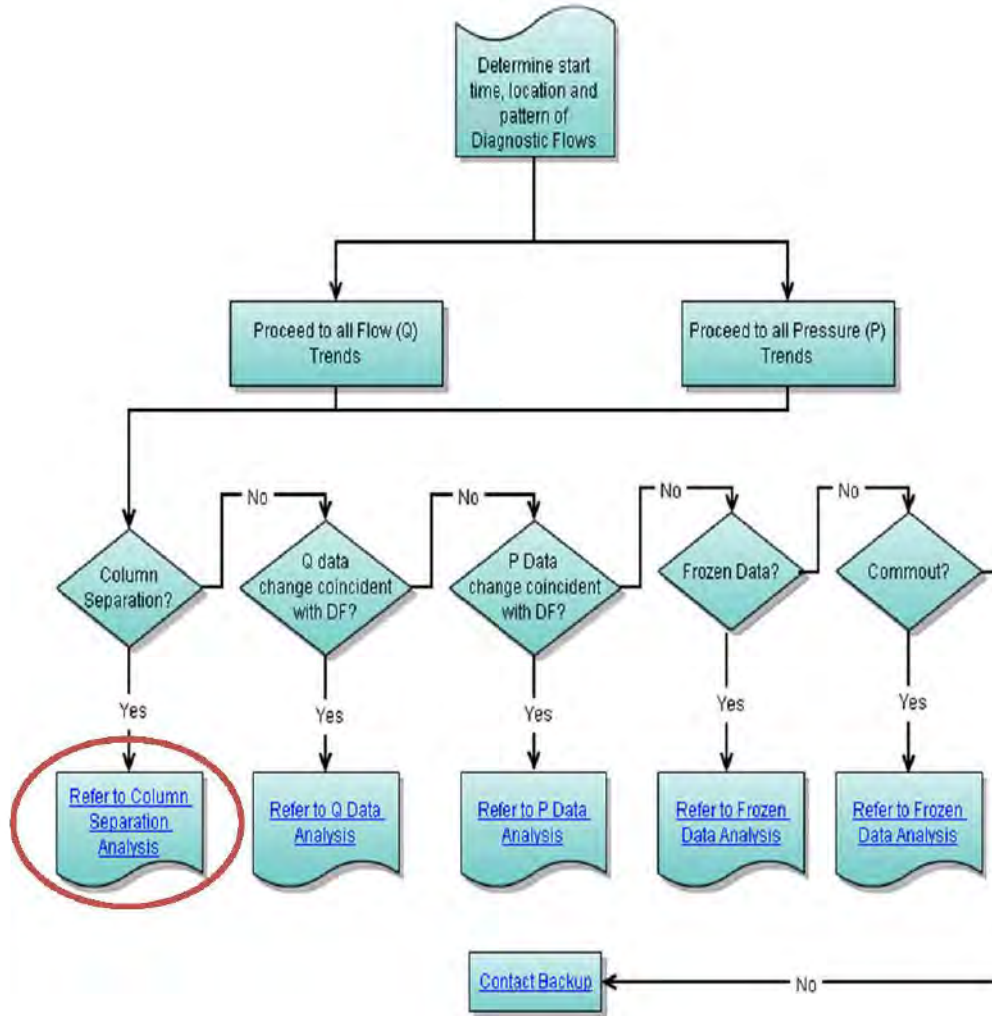
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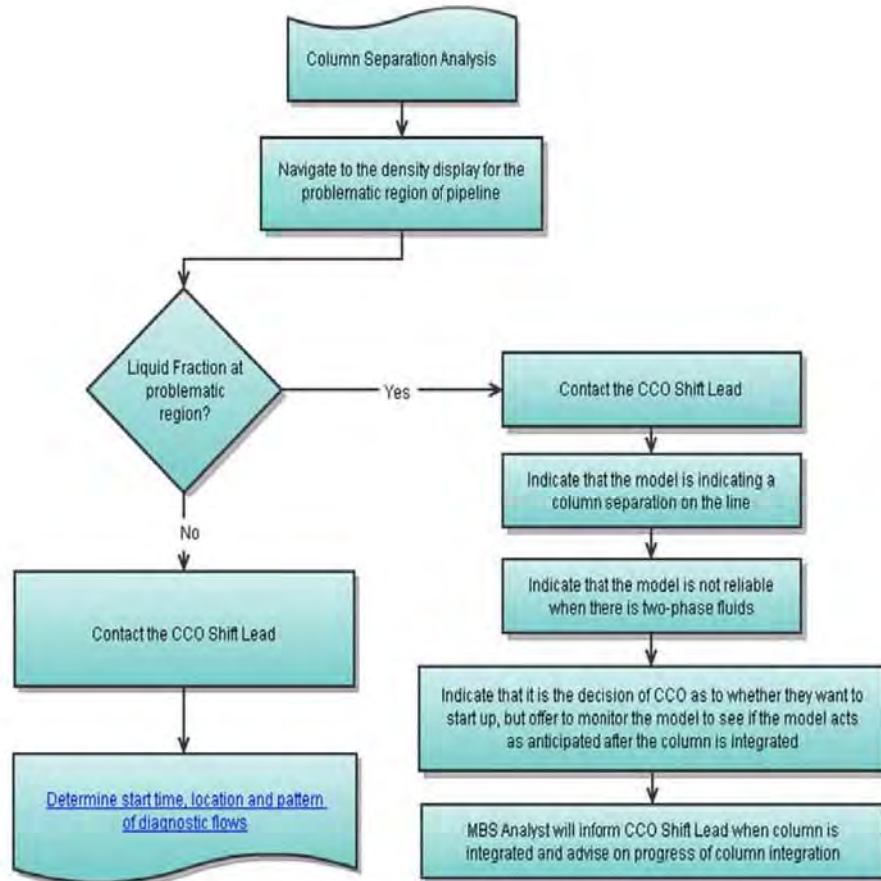


Enbridge Responses to IR No. 108
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Enbridge Responses to IR No. 108
Page 6 of 17

Final Step



Control Center Procedure for *Suspected Column Separation*

@DBTitle -

Δ Emergency Procedures-1. Emergency Response - Pipeline



k) Suspected Column Separation

In the event of a suspected column separation:

Pipeline Operator:

1. Notify Shift Lead

If a column separation is suspected from incoming SCADA data and the column cannot be restored within 10 minutes:

Pipeline Operator:

1. Notify Shift Lead
2. Shut down the specific line.
3. [Sectionalize](#)
4. [Isolate](#)
5. Execute the [Abnormal Operations Condition Reporting](#) procedure

Shift Lead:

1. Execute the [Emergency Notification](#) procedure

If field personnel locate a leak:

1. Initiate the [Confirmed Leak - Field Personnel Verification](#) procedure.

If field personnel do not locate a leak:

- permission to restart the line may be granted only by the Pipeline Control on-call designate

Related Topics:

[Line 52 Suspected Column Separation](#)

This document is valid only for the date shown: 12/14/2010

Control Center Procedure for *Column Separation*—Draft Procedure Used on July 26, 2010



Main Topic

Author: Melissa Marshall/CNPL/Enbridge **Date Composed:** 05/03/2010 09:52 AM
Subject: Suspected Column Separation
Category: Suspended Procedure Modification

Originator: Jason Ridley

Justification/Reason for Change: There are times where we have a suspected column separation and given the drained volume, cannot restore the column in 10 minutes, requiring an additional shutdown. These changes will bring our suspected column separation procedures in line with best practices.

Reviewers: CCO On-Shift Staff, Training, Technical Services, Engineering,

Primary Approver: CCO Management (Ian Melligan)

Review Period: 14 days

Procedure Section and Name(s): Section A, k) Suspected Column Separation

Notes:

- Formatted procedures have been placed in the Control Centre Operations Forum

Please provide feedback in the Control Centre Operations Forum by **May 17th**.

k) Suspected Column Separation

In the event of a suspected column separation:

Pipeline Operator:

1. Notify Shift Lead.

If a column separation is suspected from incoming SCADA data and the column cannot be restored within 10 minutes:

Pipeline Operator:

1. Notify Shift Lead.
2. Shut down the specific line.
3. [Sectionalize](#).
4. [Isolate](#).
5. Execute the [Abnormal Operations Condition Reporting](#) procedure.

Shift Lead:

1. Execute the [Emergency Notification](#) procedure.
- If field personnel locate a leak:
- Initiate the [Confirmed Leak - Field Personnel Verification](#) procedure
- If field personnel do not locate a leak:
- permission to restart the line may be granted only by the Pipeline Control on-call designate

If a starting up into a known column separation:**Pipeline Operator:**

1. Notify Shift Lead
2. Calculate the amount of volume drained (from CMT, tank levels, etc)
3. Calculate a restoration time to restore the column separation (volume drained/ flow rate) = time

Shift Lead:

1. Confirm calculated restoration time with Pipeline Operator
 2. Request Operator to start up the line into the column separation starting the 10 minute rule when the calculated restoration time expires.
- If the column cannot be restored under the above conditions:
- request operator to shutdown, sectionalize and isolate
3. Execute the [Emergency Notification](#) procedure.

Control Center Procedure for *MBS Leak Alarm*

@DBTitle -

IR 63: EMERGENCY PROCEDURES

A Emergency Procedures-1. Emergency Response - Pipeline



c) MBS Leak Alarm

If a leak detection alarm occurs:

Pipeline Operator:

1. Notify Shift lead
2. Record AOC in FACMAN

Shift Lead:

1. Assess the alarm

If any of the following conditions occur:

- A 2 hour alarm is received by itself and not in conjunction with a 5 or 20 minute alarm.
- The green line on the alarm assessment screen remains below the red alarm line for 5 minutes
- The green line drops below the red line again anytime within 20 minutes of the initial alarm
- There is any doubt about the reliability of the model

1. Execute the [MBS Alarm - Analysis by MBS Support](#) procedure

If none of the above conditions occur:

1. Execute the [MBS Alarm - Temporary Alarm](#) procedure

Related Topics:

- [Abnormal Operations Reporting Requirements](#)
- [MBS System Malfunction](#)

This document is valid only for the date shown: 08/01/2010

Control Center Procedure for *MBS Leak Alarm—Analysis by MBS Support*

- IR 63: EMERGENCY PROCEDURES

Δ Emergency Procedures-1. Emergency Response - Pipeline



MBS Leak Alarm - Analysis by MBS Support

If the Shift Lead determines that an MBS Alarm requires analysis by MBS Support:

- Notify MBS Support.

If after 10 minutes, an analysis of the alarm is not complete:

- Shut down the pipeline and standby for analysis.

If MBS Support advise the alarm is valid:

- Execute the [MBS Valid Alarm](#) procedure

If MBS Support advise the alarm is false:

- Execute the [MBS Temporary Alarm](#) procedure

This document is valid only for the date shown: 08/01/2010

Control Center Procedure for *MBS Leak Alarm–Temporary Alarm*

- IR 63: EMERGENCY PROCEDURES

A. Emergency Procedures-1. Emergency Response - Pipeline



MBS Leak Alarm - Temporary Alarm

If the Shift Lead or MBS Support determines that an MBS alarm is temporary:

Pipeline Operator:

1. Continue normal operations
 - No pipeline shutdown is required, or
 - If pipeline was shutdown, resume normal operations

Related Topics

 [Abnormal Operations Reporting Requirements](#)

This document is valid only for the date shown: 08/01/2010

Control Center Procedure for *MBS Leak Alarm–Valid Alarm*

IR 63: EMERGENCY PROCEDURES

A Emergency Procedures-1. Emergency Response - Pipeline

**MBS Leak Alarm - Valid Alarm**

If the MBS Support determines that the MBS alarm is valid:

Pipeline Operator:

1. Shut down the alarming pipeline
2. [Sectionalize](#)
3. [Isolate](#)

Shift Lead:

1. Request MBS support to provide the following information:
 - station to station estimate of the potential leak location
 - total imbalance
 - synopsis of pressure trends near the potential leak location
2. Contact the police.
 - For Norman Wells Pipeline, contact [police](#) if the emergency is within a 5 kilometre radius of Norman Wells, Tulita, Wrigley or Ft. Simpson.
3. Contact [Regional/District Management](#) and :
 - indicate that the line is shut down for a Material Balance System (MBS) alarm **only**
 - identify the potential leak location between the two identified adjacent stations
4. Contact the [CCO Admin](#) On-Call or Deisgnate

Note: Permission to restart the pipeline may only be granted by Control Centre Operations on-call designate in agreement with Regional Management

Related Topics

[Abnormal Operations Reporting Requirements](#)

This document is valid only for the date shown: 08/01/2010

Control Center Procedure for *Leak Triggers From SCADA Data*

IR 63: EMERGENCY PROCEDURES

Δ Emergency Procedures-4. Incident Analysis



Leak Triggers - From SCADA Data

Leak triggers are unexplained, abnormal operating conditions or events that indicate a leak:

From Pipeline SCADA Data:

Upstream of Suspected Leak Site:

- sudden drop in upstream discharge pressure
- sudden change in upstream control valve throttling or pump speed
- one or more upstream units shut down (or lock out) in combination with a sudden drop in upstream discharge pressure and/or sudden change in upstream control valve throttling or percentage VFD control
- sudden increase in upstream flow rate

Downstream of Suspected Leak Site:

- sudden drop in downstream suction pressure
- sudden change in downstream control valve throttling or pump speed
- one or more downstream units shut down (or lock out) in combination with a sudden drop in downstream suction pressure and/or sudden change in downstream control valve throttling or percentage VFD control
- sudden drop in holding pressure at a delivery location
- sudden decrease in downstream flow rate

From the Material Balance System (MBS):

- An MBS alarm is active

From Terminal SCADA Data:

Injection Terminals

- sudden increase in flow rate
- sudden decrease in pressure
- one or more booster pumps shut down (or lock out) in combination with a sudden decrease in pressure

Delivery/Landing Terminals

- sudden decrease in flow rate
- sudden decrease in pressure
- PCV closing

If **one or two** leak triggers occur, execute the [Suspected Leak](#) procedure.

If **three or more** triggers occur, execute the [Confirmed Leak](#) procedure.

Related Topics

[MBS Leak Alarm](#)

[Abnormal Operations Condition Reporting Requirements](#)

This document is valid only for the date shown: 08/01/2010

Control Center Procedure for *Suspected Leak–Pipeline–From SCADA Data*



Suspected Leak - Pipeline - From SCADA Data

If a leak is suspected as a result of 1 or 2 leak triggers from SCADA data:

Pipeline Operator:

1. Notify Shift Lead
2. Establish the initial time of the anomaly from historical data.
 - In the event of 3 or more Leak Triggers, execute the [Confirmed Leak - SCADA or CMT Data <Link>](#) procedure

If a leak cannot be ruled out within 10 minutes or less from the initial time of the anomaly:

Pipeline Operator:

1. Shut down the specific line.
2. [Sectionalize <Link>](#)
3. [Isolate <Link>](#)

Shift Lead:

1. Continue investigation if necessary to confirm leak triggers.
2. Execute the [Emergency Notification <Link>](#) procedure

If field personnel locate a leak:

1. Execute the [Confirmed Leak - Field Personnel Verification <Link>](#) procedure.

If field personnel do not locate a leak:

- permission to restart the pipeline may only be granted by Control Centre Operations on-call designate in agreement with Regional Management

Related Topics:

[Leak Triggers](#)

[Abnormal Operations Reporting Requirements](#)

Control Center Procedure for *Confirmed Leak–Pipeline–SCADA or CMT Data*



Confirmed Leak - Pipeline - SCADA or CMT Data

In the event of a confirmed leak from SCADA or CMT data:

Pipeline Operator:

1. Immediately shut down the specific line using the [Stop Line <Link>](#) command
 - Notify Shift Lead
2. [Sectionalize <Link>](#)
3. [Isolate <Link>](#)
4. Execute the [Abnormal Operations Condition Reporting <Link>](#) procedure

Shift Lead:

1. Execute the [Emergency Notification Procedure <Link>](#)
2. Complete the Reported Incident Information Receiving Form.

Related Topics:
[Leak Triggers](#)

Control Center Procedure for *Abnormal Operating Conditions*



a) Abnormal Operating Conditions

An Abnormal Operating Condition (AOC) is a condition that may indicate a malfunction of a component or deviation from normal operation that may:

- Indicate a condition exceeding design limits, or
- Result in a hazard(s) to persons, property or the environment

The following are identified as AOCs for Control Centre Operations. Additional conditions that could constitute an AOC according to the above definition must be reported to CCO Management.

Pipeline Obstruction

- Obstruction Triggers – Pipeline [<Link>](#)
- Obstruction Triggers – Terminal [<Link>](#)
- Pipeline Obstruction [<Link>](#)

Station Lockout

- Station Lockout [<Link>](#)

Suspected Leak

- Suspected Leak - Pipeline - From SCADA Data [<Link>](#)
- Building Leak Detected [<Link>](#)
- Densitometer Trouble or Densitometer Leak [<Link>](#)
- Station Trouble (those that state "bldg leak") [<Link>](#)
- Leak Triggers - From CMT Data [<Link>](#)
- Leak Triggers - From SCADA Data [<Link>](#)

MBS Alarm

- MBS Alarm [<Link>](#)
- MBS System Malfunction [<Link>](#)

Suspected Column Separation

- Suspected Column Separation [<Link>](#)

Communications Failure

- Communications Failure – Pipeline [<Link>](#)
- Communications Failure – Terminal [<Link>](#)

SCADA Field Equipment Malfunction

- PLC Outage – Station [<Link>](#)
- PLC Failure - Frozen Data [<Link>](#)
- Pressure Readback Outage – Station [<Link>](#)

Confirmed Leak

- Confirmed Leak - Pipeline - SCADA or CMT Data [<Link>](#)

Valve Malfunction

Control Center Procedure for *Unknown Alarm or Non Defined Procedure to an Alarm*

IR 6.1 CCO MANEUVERS

C. Maneuvers-3 Operating Standards

**b) General Operating Standards - Unknown Alarm or Non-defined Procedure to an Alarm**

In the event of an unknown SCADA alarm or a SCADA alarm without a defined procedure; Control Centre actions are based on alarm severity:

S2 Informational:

- No action required

S4 Warning:

- Discretionary Operator response to alarm dependant on operating conditions
- Notify the Shift Lead if unsure of response
- If multiple S4 alarms are active for a related issue, the response and severity may be raised
- FACMAN creation may be required
- Advise on-site/on-call personnel if required

S6 Severe:

- Notify Shift Lead
- Advise on-site/on-call personnel
- Create a FACMAN

S8 Critical:

- Notify Shift Lead
- Immediately notify on-site personnel
- Immediately call out field personnel if site is unmanned
- Create a FACMAN

Create a SCADA problem report for all unknown Control Centre alarms

This document is valid only for the date shown: 08/01/2010

Control Center Procedure for *Suspected Leak–Pipeline from CMT Volume Difference*

IR 63: EMERGENCY PROCEDURES

A Emergency Procedures-1. Emergency Response - Pipeline



Suspected Leak - Pipeline - From CMT Volume Difference

In the event of a [Leak Trigger](#) from the Commodity Movement Tracking (CMT) linefill report:

- Verify that the volumes at both the pumping and receiving stations are correct.

If the volumes are correct and exceed the [Volume Balance Threshold](#) for the pipeline:

1. Initiate a 10 minute volume check at both the pumping and receiving stations.
2. Analyze PCS historical data
 - Verify that the negative volume imbalance was accompanied by a corresponding increase in pipeline pressures
3. Compare the volumes from the 10 minute volume check

If the difference between the pumped volume and the landed volume from the 10 minute volume check is more than 10%, or if the negative volume imbalance was not accompanied by a corresponding increase in pipeline pressures:

- Execute the [Confirmed Leak - Pipeline - SCADA or CMT Data](#) procedure.

Related Topic:

[Abnormal Operations Condition Reporting Requirements](#)

This document is valid only for the date shown: 08/01/2010

Control Center Procedure for *Leak and Obstruction Triggers—On Pipeline Startup from SCADA Data*

IR 63: EMERGENCY PROCEDURES

Emergency Procedures-4. Incident Analysis



Leak and Obstruction Triggers - On Pipeline Startup - From SCADA Data

In addition to other [Leak Triggers](#) and [Obstruction Triggers](#) on a flowing pipeline, the following trigger

In the event that pressure changes do not propagate throughout a pipeline segment within the expected Wave Travel Time:

If the event is accompanied by an unexplained, abnormal increase in pressure:

- execute the [Suspected Pipeline Obstruction](#) procedure

If the pipeline was shut down with sufficient pressure to maintain [Minimum Holding Pressure](#) in the pipeline segment:

- execute the [Confirmed Leak](#) procedure

If the pipeline was shut down with insufficient pressure to maintain [Minimum Holding Pressure](#) in the pipeline segment:

- execute the [Suspected Column Separation](#) procedure

Related Topic:

Sample Estimated Wave Travel Time (Miles):

| Segment Length (mi) | Wave Travel Time |
|---------------------|------------------|
| 30 | 45 sec |
| 40 | 1 minute |
| 60 | 90 sec |
| 80 | 2 minutes |

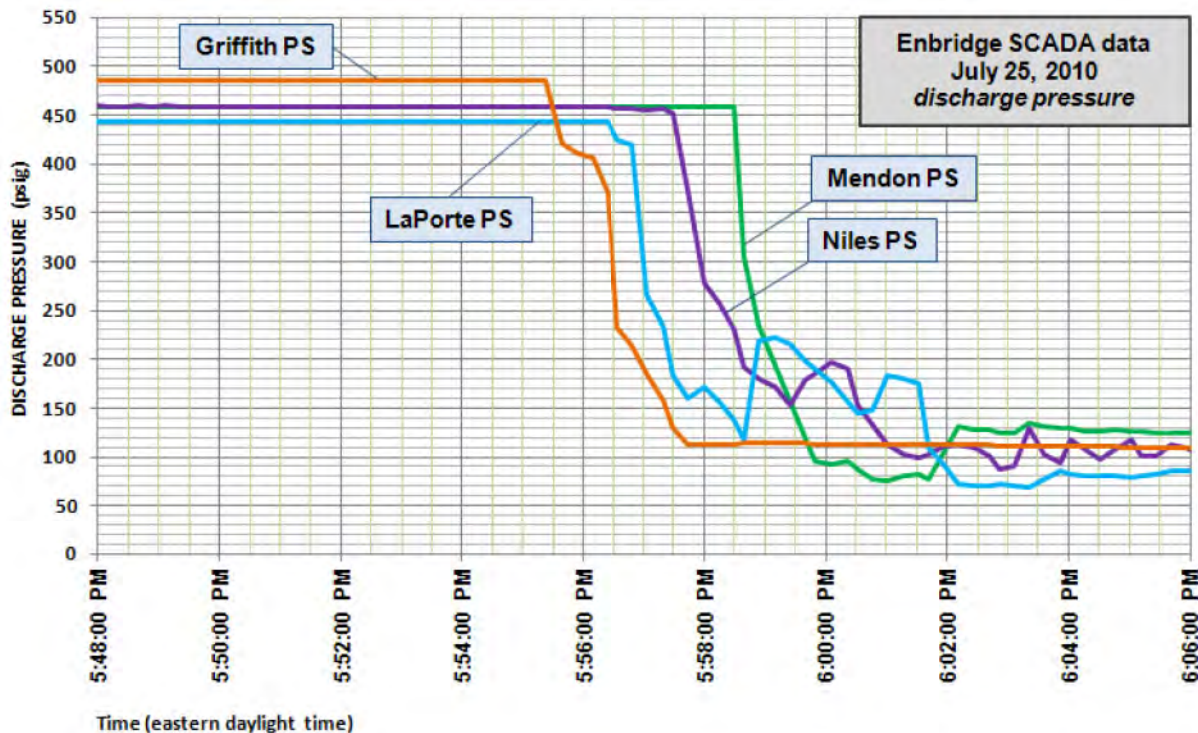
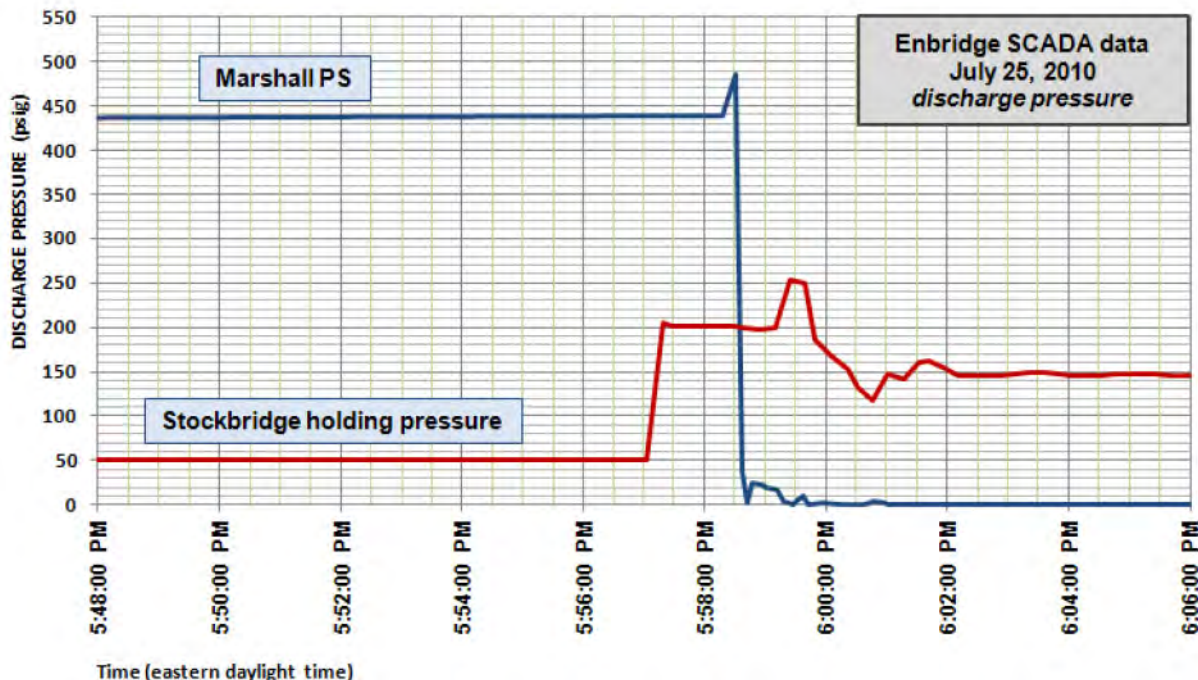
Sample Estimated Wave Travel Time (Kilometers):

| Segment Length (km) | Wave Travel Time |
|---------------------|------------------|
| 40 | 40 sec |
| 60 | 1 minute |
| 100 | 100 sec |
| 300 | 5 minutes |

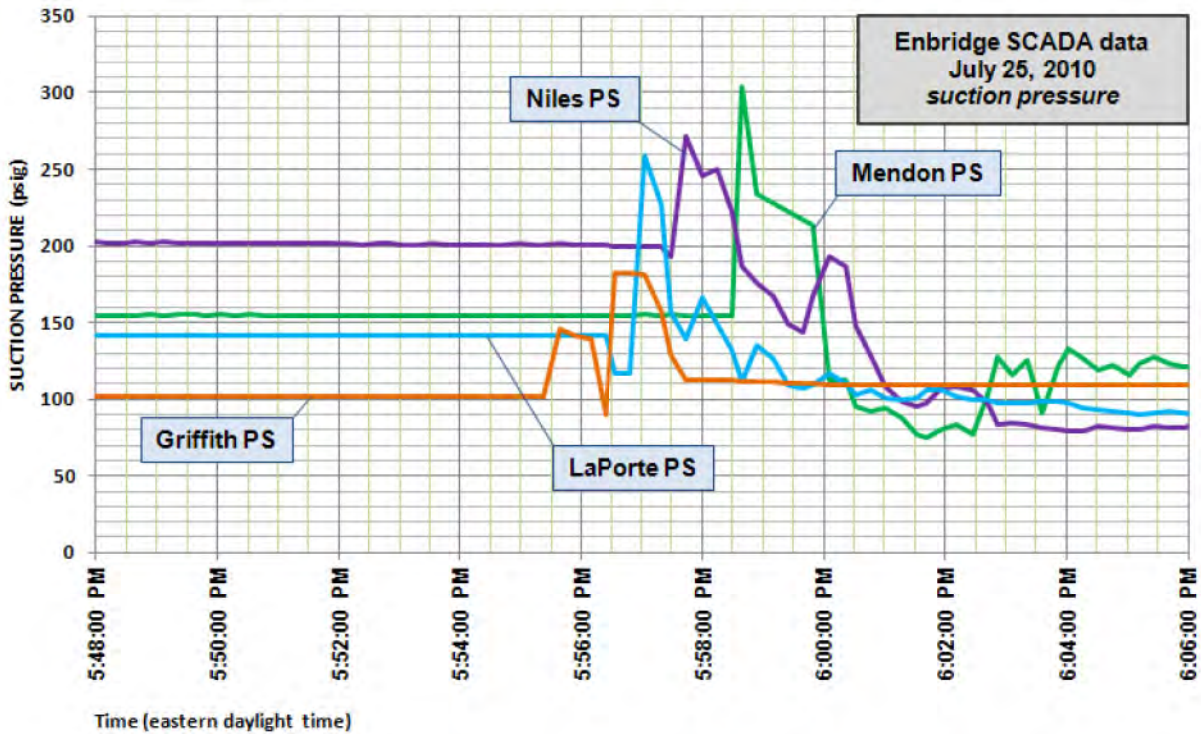
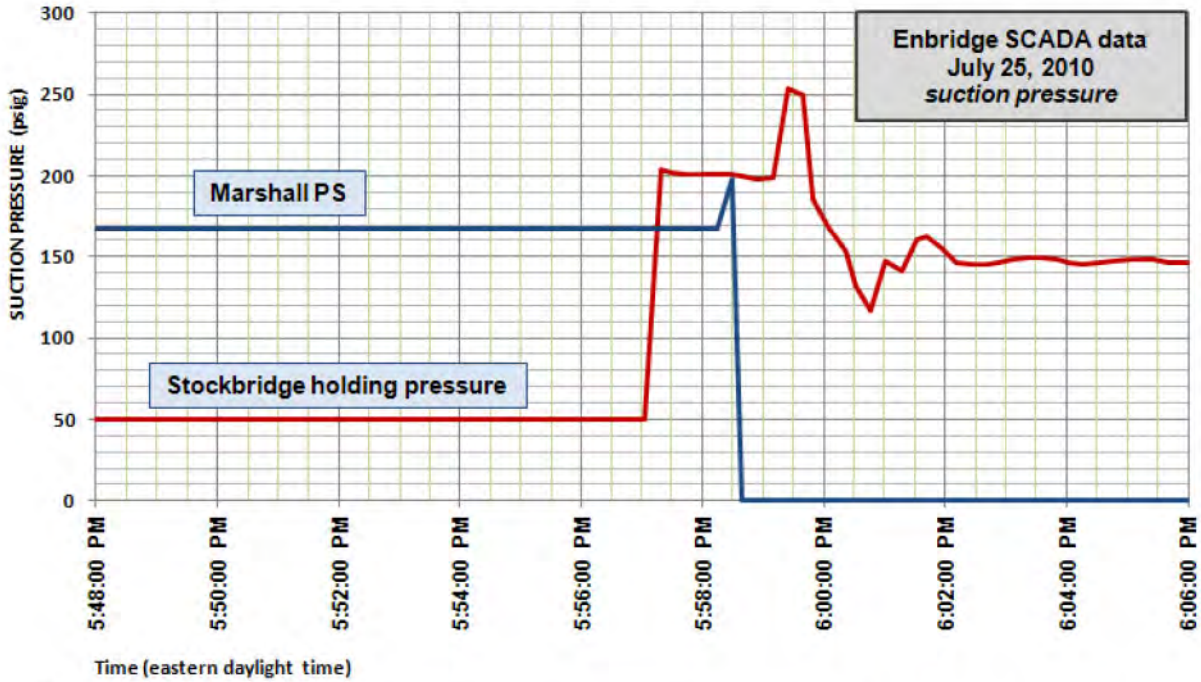
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5.3 Appendix C: Supervisory Control and Data Acquisition Plots

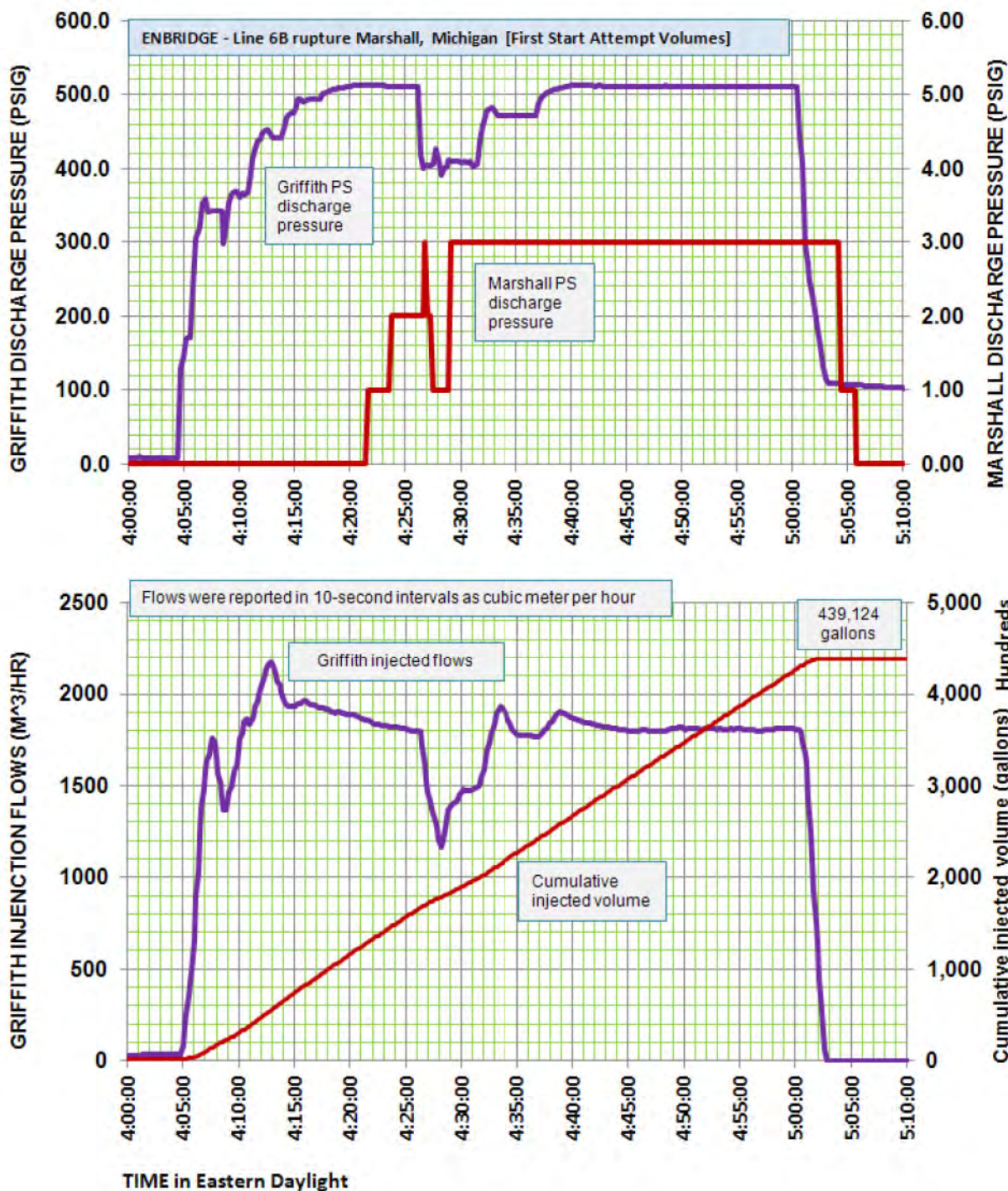
SCADA Discharge Pressure Recorded at the Time of Rupture



SCADA Suction Pressure Recorded at the Time of Rupture



SCADA Pressure and Volumes Pumped—Startup One



SCADA Pressure and Volumes Pumped—Startup Two

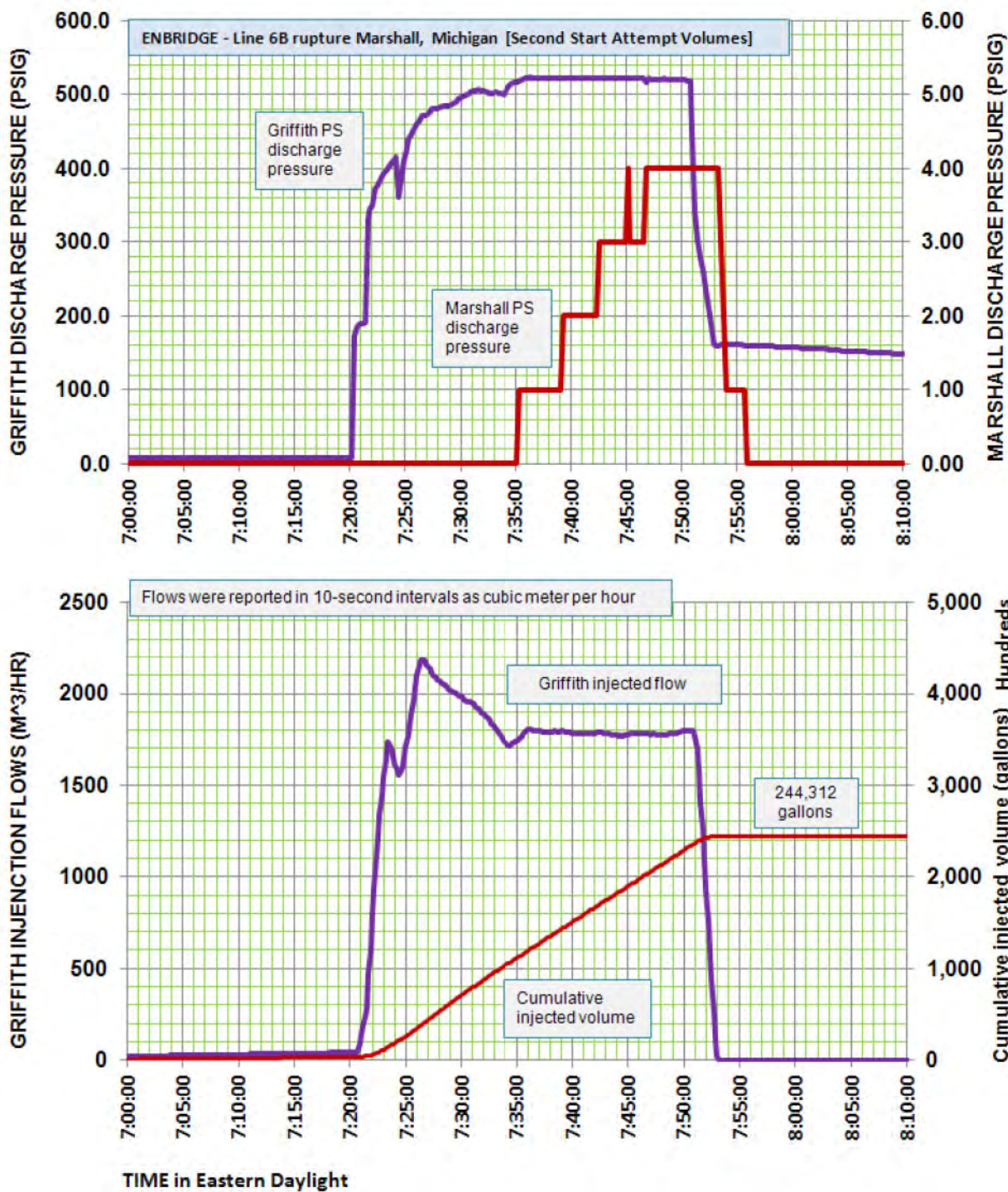


EXHIBIT BMC-59

[House Hearing, 111 Congress]
[From the U.S. Government Publishing Office]

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February 3, 2023
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THE SAFETY OF HAZARDOUS
LIQUID PIPELINES (PART 2): INTEGRITY MANAGEMENT

=====

(111-128)

HEARING

BEFORE THE

SUBCOMMITTEE ON

RAILROADS, PIPELINES, AND HAZARDOUS MATERIALS

OF THE

COMMITTEE ON
TRANSPORTATION AND INFRASTRUCTURE
HOUSE OF REPRESENTATIVES

ONE HUNDRED ELEVENTH CONGRESS

SECOND SESSION

July 15, 2010

Printed for the use of the
Committee on Transportation and Infrastructure

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HEARING ON THE SAFETY OF HAZARDOUS LIQUID PIPELINE (PART 2): INTEGRITY
MANAGEMENTTestimony of Richard B. Kuprewicz
BMC-59 (RBK-11)
February 3, 2023
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Thursday, July 15, 2010

House of Representatives, Subcommittee on
Railroads, Pipelines, and Hazardous
Materials,
Committee on Transportation and Infrastructure,
Washington, DC.

The Subcommittee met, pursuant to call, at 10:00 a.m., in room 2167, Rayburn House Office Building, Hon. Corrine Brown [Chairman of the Subcommittee] presiding.

Ms. Brown of Florida. The Subcommittee on Railroads, Pipelines, and Hazardous Materials will come to order.

The Subcommittee is meeting today to hear testimony on pipeline operation management of the safety of hazardous liquid pipelines, more common known as ``integrity management.'' This hearing is the third in a series of oversight hearings the Subcommittee will hold as we look toward reauthorizing the Department's pipeline safety program.

On February 1, 2000, in the wake of several tragic pipeline ruptures, PHMSA issued a Final Ruling, requiring pipeline operators to develop and implement a written Integrity Management Program. Under the program, operators are required to identify all of their pipeline segments that could affect a high-consequence area, such as a high-population area, an environmentally sensitive area, evaluate the integrity of such pipeline segments and repair and report certain defects identified as a result of these evaluations.

A lot of successes came out of the Integrity Management Program. For example, operators have reported to PHMSA that they have made more than 31,000 repairs to hazardous liquid pipeline segments, that if left unaddressed, could have resulted in a spill. Of these, about 7,000 detects were considered to be so serious that immediate repairs were required under the regulations. Another 25,000 detects had to be repaired within a 60- to a 180-day time period.

This is a real success, and I anticipate that we will see similar successes from the gas Integrity Management Program, but there is always room for improvement, and that is why we are here today.

I hope we can get some of the areas that might need some refined tuning up front. We do have concerns about the Integrity Management Program of BP Exploration and Alyeska Pipeline Service. BP, as evidenced by the Deepwater Horizon spill, has a long history of taking too many risks and cutting corners to pursue economic growth and profits. BP Exploration was invited to this hearing, but could not attend.

Recent press reports allege that Alyeska, at the direction of BP, which owns almost 50 percent of the company, is following in BP's footsteps by making dangerous cuts in safety and inflating the amount of money the company is spending on corrosion control. A day after these reports surfaced, the Alyeska President, who has worked for BP for almost 27 years, announced his resignation. Alyeska stated that his retirement was already planned, but the timing of this most recent announcement is questionable.

I am concerned about a few recent incidents at Alyeska, one of which was a near miss incident that resulted in the release of flammable vapors. According to PHMSA's Corrective Action Order, Alyeska did not verify the safety of the pipeline

before it restarted operations.

Another incident occurred at Pump Station 9, which lost power during firing testing. As a result, the station dropped off the radar screen at Alyeska Pipeline's control center. Crude oil began to flow without anyone realizing it, and in the end, 22,000 barrels of oil flowed into a relief tank and then spilled over, spilling another 5,000 barrels of oil onto the ground. Alyeska seemed to minimize the significance of this spill in its written testimony, stating that, because the oil spilled into secondary containment, no environmental damage or injuries occurred. The fact is, while the lining of the containment area is designed to prevent oil from leaking into the soil, when crude oil meets the air, it releases toxic gas. These gases have been proven to cause significant health effects in humans, and workers involved in the cleanup of this spill suffered the highest level of exposure.

This last month, the National Institute of Environmental Health Sciences testified before Congress that, historically, the workers involved in the cleanup have reported the highest level of exposure and most acute symptoms when compared to subjects exposed in different ways. So I would caution Alyeska against minimizing the impact of this incident.

With that, I welcome today's panelists, and thank you for joining us. I look forward to this hearing.

I am pleased to introduce the Honorable Cynthia Quarterman, who is the Administrator of the Pipeline and Hazardous Material Safety Administration.

Welcome. We are pleased to have you here with us this morning. Your entire written statement will appear in the record. Madam Administrator, please proceed.

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STATEMENT OF THE HON. CYNTHIA L. QUARTERMAN, ADMINISTRATOR,
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Ms. Quarterman. Thank you. Good morning.

Chairwoman Brown, Ranking Member Shuster, if he should show up, and Members of the Subcommittee, thank you for the opportunity to appear today.

Secretary LaHood, the employees of Pipeline and Hazardous Material Safety Administration, and the entire Department of Transportation all share public safety as their top priority. The Department is committed to preventing spills on all pipelines through aggressive regulation, oversight and enforcement.

PHMSA is focused on improving the integrity of pipeline systems and reducing the risk of pipeline failure. Integrity Management Programs were created to ensure pipeline integrity in areas with the highest potential for adverse consequences, promote a more rigorous and systematic management of pipeline integrity and risk, improve the government's prominent role in the oversight of integrity plans, and assure the public's confidence in the safe operation of the Nation's pipeline network.

PHMSA's regulations consist of prescriptive measures pipeline operators must follow and perform at standards that consider a pipeline's unique characteristics and operating conditions. Together, these regulations seek to prevent the leading causes of pipeline failure, and require operators to implement corrosion prevention, leak detection, and leak containment technologies.

Integrity Management Programs ensure pipeline operators adequately identify, evaluate, and address risks of the entire pipeline systems. The integrity management rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the liability of hazardous liquid

pipelines in or near high-consequence areas. That rule also emphasizes the prompt detection of leaks through the monitoring of operational parameters and engineered leak detection systems. In addition, Integrity Management Programs are intended to improve an operator's analytic processes and risk management. We are proud to say integrity management is working.

Since this program has been mandated, all hazardous liquid pipelines within high-consequence areas have been assessed. That assessment resulted in the identification and repair of over 35,000 dangerous conditions. In addition, 86 percent of hazardous liquid pipeline mileage has been assessed, and an additional 78,000 anomalies outside of high-consequence areas have been remedied.

PHMSA has also ensured that operators comply with corrosion standards through inspection and aggressive enforcement. Since 2000, PHMSA has issued 657 probable violations or procedural inadequacy notices involving corrosion, and has proposed \$1.7 million in fines.

PHMSA has taken unprecedented steps to inform the public and all stakeholders about the protections provided by the Integrity Management Program and PHMSA's oversight. PHMSA has an integrity management Web site to provide information to the public on the rule as well as PHMSA's oversight of the program. This publicly accessible Web site includes hundreds of frequently asked questions to explain the rule's provisions and PHMSA's expectations. This transparency helps PHMSA improve its oversight and increase its stakeholder understanding and evaluation of its program.

PHMSA looks forward to working with Congress to address issues related to hazardous liquid pipeline safety, including finding ways to be more effective in preventing pipeline failures and mitigating the effect of any failure. PHMSA very much appreciates the opportunity to report on hazardous liquid pipeline Integrity Management Programs.

I would be happy to answer any questions that you might have today. Thank you.

Ms. Brown of Florida. Thank you.

Mr. Walz, you can ask any questions or make any opening statement that you want.

Mr. Walz. Thank you, Madam Chairwoman, and thank you for holding this important hearing. I certainly wish more of my colleagues were here.

Ms. Quarterman, thank you for coming back here again. You have been a regular up here, and I appreciate that. Just a couple of thoughts for you.

In 2006, the Inspector General over at DOT reported concerns about operators' overreliance on integrity management assessments. Is that a concern of yours or have we fixed that in the subsequent 4 years?

Ms. Quarterman. I don't believe there were any specific recommendations that came out as a result of the IG's findings. However, the program did go in and try to remediate the concerns that were addressed by the Inspector General by following up on reporting errors that had been made by operators, and now it is a regular part of our inspection protocol that they should review reports that have been made and whether the data has been accurate or not.

Mr. Walz. OK. Tell me through this procedure, if you can, Ms. Quarterman: How do I know of the integrity and of the safety of the pipelines in southern Minnesota today? How would I go about finding that out? How do I know? How do I verify? How do I assure that somebody is not just checking the block on a form? How do I know that that integrity is real, in the ground, and how do we verify that?

Ms. Quarterman. Well, the operator is the first person responsible for ensuring that the integrity of a pipeline is sound. Historically, the program had produced a series of regulations that were very prescriptive in nature and essentially required or allowed a pipeline operator to just comply with those minimal technical requirements. The inspectors at the time would go out and do what you said, essentially check a box to make sure that those prescriptive requirements were met.

The Integrity Management Program was intended to create a systematic approach for pipeline operators, one in which the inspectors could check what they were doing. The Integrity Management Programs should take into account the individual characteristics of each operator's pipeline--size, location, product being shipped, all of that.

As a result of that program being in place, we have created a new inspection protocol, and I will tell you our Integrity Management Program inspections usually include three to five engineers on a team, and they go out for 3 to 4 weeks. This is the inspection protocol that they go through. It is extremely thorough, extremely complicated.

Mr. Walz. This comes to a good point, and I was going to ask: Are all pipeline operators created equal? Obviously not in terms of size, product and all that. Are they created equal in their culture of safety?

Ms. Quarterman. Unfortunately not.

Mr. Walz. OK. Does the Integrity Management Program compensate for that in terms of assuring public safety if we do have--for lack of a better term--a bad actor in this business? Are we capturing that or does it come back to the issue, as you said, of fundamentally when I asked the question of southern Minnesota, and you said it basically falls upon the operator?

Ms. Quarterman. Well, that is the first line of defense. We do have inspectors to go out and inspect, obviously. The purpose of the Integrity Management Program was to do just what you said, to try to help embed into the industry a culture of safety by requiring them to look at the details of their operations and go through an assessment of their pipeline and of the situation surrounding their pipelines to come up with the best plan for their particular pipelines as opposed to just abdicating responsibility altogether and saying, OK, well, our pipeline meets a certain recommended practice in terms of the type of steel, and that is it.

Mr. Walz. Is it unfair for us to draw conclusions to Deepwater Horizon and how the integrity management there was given over to the operators, obviously, to a point where we didn't catch an error? Is that unfair? Is it apples to oranges here or is it similar in terms of the culture and the redundancies of safety to say, yes, Deepwater Horizon should show us something about pipelines?

Ms. Quarterman. Well, I think there are lessons for all of us to learn from the Deepwater Horizon incident.

One of those lessons--and I know there is an ongoing investigation, but based on the public information that has been made available is the role of contractors in industry, and it is not just in offshore operations. It is true across all industries, and it is also true in the pipeline industry and one in which we have to take a very close look at how operators are managing their contractors.

We are reviewing opportunities to create a further system for quality management systems to ensure the contractors that are hired by companies meet the same requirements as those people who are on the ground every day--or who should be on the ground.

Mr. Walz. Very good. Thanks, Ms. Quarterman.

I yield back.

Ms. Brown of Florida. Thank you.

Mr. Shuster.

Mr. Shuster. I thank the Chairwoman, and I welcome the administrator. You have become a regular guest with us here. I appreciate your coming up here and spending time with us.

I really don't have any questions for you. I think I will probably ask you many times over all the questions that I have.

I am not going to read my whole statement, but I would like for the entirety to be put in the record.

I would like to point out that, of course, today's hearing is on Integrity Management Programs and that pipelines are only required by law to test the high-risk areas, but in practice, many of them do much more than that. Our next witness from Enbridge will talk about how only 40 percent of their system is in high-risk areas, but they perform internal inspections on nearly 100 percent of their pipelines. Only 40 percent of the Transatlantic Pipeline passes through high-risk areas, but they hold the entire pipeline to the high-risk standard. So I think that is important to point out.

Again, thank you, Administrator Quarterman, for being here, and I look forward to hearing our other panel of witnesses.

I yield back.

Ms. Brown of Florida. Thank you.

Mr. Cummings.

Mr. Cummings. Thank you very much, Madam Chairlady, and thank you for holding this hearing.

Ms. Quarterman, let me just ask you a few questions.

According to your Web site, since the integrity management rule was implemented in 2001--is that right? Was it 2001?

Ms. Quarterman. It essentially started around 2000, 2001, 2002. There was a layering of who it was applied to.

Mr. Cummings. Since that time, pipeline operators have made almost 32,000 repairs to hazardous liquid pipeline segments that could have affected a high-consequence area if there was a release. How does PHMSA verify that each of these repairs has, in fact, been made and made to a standard that would be satisfactory?

Ms. Quarterman. During our integrity management inspection process, we review the data that the operators have that show where these particular anomalies were and the fact if they were repaired or not. There may be spot-checking on a particular repair, but we certainly are not there every day to review it as a repair is done. We do, during our inspection process, do a thorough review of those particular incidents where they should have done a repair to ensure that it has been performed.

Mr. Cummings. But is that spot-checking? I mean do you actually go out and look at each situation?

Ms. Quarterman. We don't have the personnel to go out and look at each situation.

Mr. Cummings. So it is just a matter of taking somebody's word. Is that basically it?

Ms. Quarterman. On an annual basis, the management of each pipeline operator has to certify the reports of repairs that have been performed on their pipeline. So, while we can't go out there individually, if it were the case that someone fraudulently wrote down that they had done a repair, we would be, obviously, able to go after them on criminal charges.

Mr. Cummings. Well, you know, one of the things that we have seen with BP is--and I am trying to put this nicely. There have been some questionable integrity issues, and the sad part is, when these issues come along, they cannot only be harmful--they can be deadly--and I guess sometimes management has to say to themselves, you know, do I take the risks? I mean is profit more important than safety?

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I guess I am just asking: Has there ever been a time when folks actually went out and even spot-checked, I mean at any time? Do you follow me?

Ms. Quarterman. Yes, I follow you.

Mr. Cummings. We are talking about verifying. Just going back to Ronald Reagan, you know, you can believe them, but you have got to verify.

I guess the only reason I am raising this is because of the situation that we find ourselves in right now where we assume--see, sometimes in this country, I think we assume too much. We assume, assume, assume, and we assume that when the rubber meets the road that everything is going to be fine. Then when the rubber comes to meet the road, we discover there is no road. I think that is what happened in Katrina. I think that is what has happened here.

Also, as Chairman of the Coast Guard Subcommittee, I talk about this whole idea of making sure that there is integrity in all of our systems. So I was just wondering.

Go ahead.

Ms. Quarterman. Yes, we do do field inspections that spot-check repairs. When an inspector goes in to look at the integrity management plan, they look at the list of locations where these significant anomalies were found as well as the repair record to double check and make sure that there is support for the fact that a repair was done. In addition, there are spot-checks done in the field.

Mr. Cummings. You know, the IRS, when you talk to them about why they audit people, there are certain things that they put in their computer, certain information that triggers inspections. I was wondering, is there any triggering information, mechanisms, data, whatever, that would automatically cause alarm bells to go off and for you all to do these spot checks you are talking about other than your routine ones?

Ms. Quarterman. Well, certainly, if in looking at the paperwork something were to appear to be amiss--and I can tell you there has been an instance where some welding records were amiss, and we are following up on that--then they would go and check it.

So, yes. The inspectors are engineers, and they are trained to look at this data, and if something looks weird--for example, if a record keeps repeating itself over and over and over again and it is clear it is not addressing the issue--then, yes, there are triggering mechanisms.

Mr. Cummings. Thank you very much, Madam Chair.

Ms. Brown of Florida. Thank you.

Mr. Teague.

Mr. Teague. Yes. Thank you, Madam Chairwoman, for having this meeting and for letting me be here.

A couple of questions, I guess, were already asked, but I wanted to ask them a little bit differently.

In talking about the integrity test that we run, is there a standard frequency of time that we run those tests depending upon the size of the line or the pressure of the line?

Ms. Quarterman. Under the Integrity Management Program, there was a requirement that operators do an assessment, most of which were inline inspections with pigging instruments within a certain time period. That time for most operators ended either at the end of 2008 or at the beginning of 2009, and this was in high-consequence areas, and then they had to reassess again 5 years later. They had to start with their riskiest 50 percent and then do the last 50 percent, look at those assessments and determine which ones, based on our standards, were the most problematic, fix those first, and go from there. Most operators are now in that reassessment period,

meaning that they are beginning to do a second run of those high-consequence areas.

Mr. Teague. Do we know the way that it is set up in that 5-year time frame? Is every single line tested?

Ms. Quarterman. Every line that is in a high-consequence area must have a test, and I said 5 years. Five years is the outlying number. If an operator determines that, because of the attributes of their particular line that it should be tested more frequently than that, then they should do that. That would be part of their plan. In 5 years--or I think it is 68 months at the outside--they must be retested.

Mr. Teague. But we know that every line is tested at least once every 5 years?

Ms. Quarterman. Right. In high-consequence areas, yes.

Mr. Teague. Are we ever on site when they test the lines?

Ms. Quarterman. Not always, no. Occasionally, we go after, usually, the assessment has been done to see what has occurred and what anomalies have been found and how they have remediated it.

Mr. Teague. When do we get the test results? Like, if they test the line today, when do you get the test results?

Ms. Quarterman. We do not receive the data in-house at the time it is tested. When we go out on an inspection, we review their records there, so we don't have a repository of their data.

Mr. Teague. When you do go out and do the on-site testing, do you just go to their office and review the test results from that or are you actually there like when they put the pig in the line and drive down the road and be there when they pick the pig up?

Ms. Quarterman. Most of what we do is reviewing the paper records. We do do spot tests, and we are there on occasion when people are pigging their line. We simply don't have the resources to be at every assessment.

Mr. Teague. But you are at some on-site tests to see them put the pig in and see them take the pig out?

Ms. Quarterman. Yes. Yes.

Mr. Teague. Are there any other tests or requirements to the pipeline as to the type of material, the wall thickness or anything else when it is installed?

Ms. Quarterman. Before a pipeline is installed, this is in the construction phase, it has to go through a hydrostatic test to ensure they can operate above the maximum allowable operating pressure on the line.

Mr. Teague. You said a while ago that we had collected a large amount of money, millions of dollars in fines. What happens with that money?

Ms. Quarterman. That money is returned to the Treasury.

Mr. Teague. OK. You know, there was a question asked about how comparable this should be to the Deepwater Horizon, and was it apples and oranges. You know, I do think that it is apples and oranges. I don't think there is much more comparison to this and the Deepwater Horizon than there is to this and driving unless, maybe, the Pipeline and Hazardous Material Safety Administration--we are not in any comparison to MMS or anything in the way that we are operating.

I mean, if there are comparisons to pipeline safety and Deepwater Horizon, is there a comparison also to Pipeline and Hazardous Material Safety Administration and MMS?

Ms. Quarterman. MMS regulates drilling operations, and PHMSA regulates pipeline operations. The differences between the two are that, in the instance of a drilling operation, as we have seen it in Deepwater Horizon, there is the opportunity for a blowout, which has an unlimited flow of oil. In the instance of a pipeline, it is sort of like a garden hose in

that it has a finite amount--well, it is not like a garden hose in that it is finite, but it does have a finite amount of product in it. There are valves that can be shut off, so there is a finite amount of spill that can occur as a result of an incident.

Mr. Teague. OK. In regards to our testing and spot-checking and stuff like that, do you think we are a lot more efficient than MMS apparently was in what they were doing?

Ms. Quarterman. I can't really speak to that.

Mr. Teague. Thank you.

Ms. Brown of Florida. Ms. Richardson.

Ms. Richardson. Thank you, Madam Chair, and thank you for having this very timely hearing in the series that we have been going through.

Administrator, thank you for being here. I have about four or five questions if we could go through them as quickly as possible.

From 2000-2008, the U.S. DOT Pipeline and Hazardous Material Safety Administration reported on its Web site that 21 oil spills occurred in my district, California's 37th Congressional District. Between 2005-2009, the national average stated that 68 percent of the total incidences were reported to your administration but were not made public via your Web site. My questions are:

How many oil spills or incidents have occurred in the 37th Congressional District? I would like to know the number of what was reported and not reported.

Ms. Quarterman. I will have to get you the details for your particular district. I can tell you that the reporting requirements have changed and have been reduced over time, so now 5-barrel spills are being reported, and maybe that is the difference between the data, but I am not sure about that. We would have to verify that for you.

Ms. Richardson. Who are they reported to besides your Web site? Are the Members notified?

Ms. Quarterman. They are reported to us, and we put it on the Web site, and it is available to the public. If you would like to have notification of every instance that occurs in your district, we would be happy to do that.

Ms. Richardson. Well, I think, for this Committee's jurisdiction, it might be helpful to have an ongoing report on a periodic basis and then, that way, Members who have this interest would have the ability to check, but I would like my district's information.

Ms. Quarterman. Absolutely.

Ms. Richardson. My next question is: Do you believe that 21 spills are large enough to change the current process and consider that that is probably not an acceptable number and how communities should be maybe more engaged in what is happening?

Ms. Quarterman. Well, I think there should be no spills, and that is our goal and what we are working towards. I can tell you that the number of spills has been reduced by about 50 percent over the past decade or so.

Ms. Richardson. These were 21 within this decade, 2000-2008.

Ms. Quarterman. I am just saying from the beginning of the decade until today that the number of spills has gone down dramatically, but it has not gone to zero, which is our ultimate goal.

In terms of how communities can be involved, there are a number of grants that PHMSA provides to communities, especially those interested in being involved in the pipeline safety program, one of which is a base grant to a State if they would like to assist by having an agreement with PHMSA. California is a State that has an agreement with PHMSA to oversee the

pipelines within their State. On top of that, there are State damage prevention grants that are provided to States so they can help ensure that pipelines are not damaged within their communities.

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There are also 811, or One Call Grants, that are useful, because one of the leading causes of pipeline incidents is excavation damage, and that is to assist communities in providing information to the public about calling 811, so before they dig, they know the location of a pipeline. There are also----

Ms. Richardson. I am down to a minute and 30 seconds. If you could supply that to us, that would be sufficient.

Ms. Quarterman. Absolutely.

Ms. Richardson. I have several other questions along the same line.

After the first round of operator-performed assessments that were completed in February of 2009, pipeline operators reported to your organization that they had made 31,855 repairs in high-consequence areas. My question is:

How many repairs were performed in my district, and do you have a map or data that informs people of exactly where the repairs are made?

Building on that same question, in my district we contain 643 total pipeline miles, and 558 of those consist of hazardous liquid pipeline. My question is:

Are these pipelines regulated? Have they been inspected? What type of inspection has been done, and what is the condition that has been found?

Then finally--I have got about 34 seconds--I recently had the opportunity this last weekend to spend some time in the Gulf for about 2-1/2 days. One of the things that I saw that seemed to be a problem is we could have had the companies better required to have the resources in place to handle a spill better. I don't know if that is a shared resource that companies in the area all have, you know, those devices. So my question would be and if you could supply it to this Committee:

What materials are required? If in the event you were to have an incident, what are those that you know of?

One of the things we found out in the Deepwater Horizon situation is we found out that many of the things we were using weren't effective. So to what degree has your group documented? What resources would be needed? Are they being stockpiled appropriately in the areas that need them? Because we didn't have enough booms. We are still in, you know, day 80-something, and we don't have enough boom material. We don't have enough skimmers. They are now getting this air-conditioned kind of mat material, and we shouldn't be doing that after the incident. We should know what is needed, and it should be sufficiently available so we can respond.

So, if you could provide this Committee that information, it would be helpful. Thank you very much for your time.

Ms. Quarterman. Sure. Thank you.

Ms. Brown of Florida. Would you like to respond to any part of her questions?

Ms. Quarterman. Well, as to the specifics with respect to the district, we will provide that to the record.

On the oil spill response, I will say that PHMSA issued a safety advisory a few weeks ago to all of the onshore oil pipeline operators. That is our responsibility to make sure that those plans are in place, asking them to review their oil spill response plan in light of Deepwater Horizon to make sure that their worst case spill is accurate and that the personnel that they have identified and the resources they have identified are available and capable of responding to a spill if it is a worst case spill. We gave them an exception for,

obviously, a response that is necessary for Deepwater Horizon, but we want to make absolutely sure that the oil spill plans that are in existence for the onshore pipelines are the best they can possibly be.

Ms. Richardson. Madam Chair, if I could just respond to that very briefly.

I think, though, the problem is we need more than a plan. We need to know: Do you physically have the boom? Do you physically have the skimmers? Do you physically have whatever it is, and is someone within your organization checking to see that it is there? Because, if there is anything we have learned, it is that we need more than a plan. We need to know that it is not just a plan and that it is actually something that is ready to do.

Thank you, though, and I do appreciate your efforts in these tough times.

Ms. Brown of Florida. Thank you, Ms. Richardson.

If the Members would like, we could have another round.

Mr. Sires.

Mr. Sires. Thank you, Madam Chair, for holding this hearing, and I apologize if this question was asked before.

I come from a very congested area. Just to give you an idea, the town that I live in is 1 square mile, and we have 50,000 people, so pipelines going through some of this area is one of my biggest concerns, especially in a congested area.

I know that we check the pipelines every 5 years. I was just wondering if it is prudent in heavily congested areas to increase that and make it less than 5 years. I was just wondering what you think of that. I am concerned about the safety feature of it, the safety factor of it.

Ms. Quarterman. I am concerned as well.

A congested area, as you referred to, a highly populated area--and I live in one as well--is one that would be considered a high-consequence area. In those instances, the operator should be considering whether it is appropriate to do more frequent assessments of those pipelines in those areas given the situations that they run into in that particular area. Whether or not doing it more frequently would make a bigger difference, I don't know. We haven't looked at that issue.

Mr. Sires. Can you handle more frequent inspections? You know, can you handle the paperwork and all the things that go with it?

Ms. Quarterman. Well, now I am talking about assessments. This is something that the operators, themselves, do with these tools.

Mr. Sires. Right.

Ms. Quarterman. Then we go in and inspect after the fact. We would probably require more inspectors in order to do more frequent inspections, absolutely.

Mr. Sires. What can we do in Congress to make that happen for you? Don't ask for too much.

Ms. Quarterman. Well, additional resources are always welcome.

Mr. Sires. Just additional resources?

It is just that, you know, in my district, every time you dig something up, there is a problem. I am talking now as a former local mayor. Even to do a sidewalk, you have got to worry about cables and so forth. So, as to the fact that excavating in many of these areas may not damage the pipe right then and there, it might just make it where, down the line, it would be a problem. So that is when I ask you, in terms of heavily populated areas, that I think we need to make it more often. I think I pointed out to you the Edison accident years ago. That is how dangerous it is.

So I don't have any further questions. Thank you very much.
Ms. Brown of Florida. Thank you.

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Ms. Quarterman, according to your Web site, pipeline operators report 32,000 defects were found outside of high-consequence areas.

Is this reporting a requirement by regulations or is it voluntary? If operators find defections outside of that area, the high-consequence area, do the operators have to repair these defects in accordance with the integrity management rule? If not, do you think they should report on it and repair these defects?

Ms. Quarterman. There is no requirement that they report that information. I imagine that people are reporting it to get credit to show that they were doing, not just what is required by the rule, but above and beyond what is required by the rule.

There are no requirements that those anomalies that have been found in areas out of high-consequence areas meet the terms of the integrity management rule. I would say that a prudent operator and one with a strong safety culture, once they find the indication of an anomaly of great concern, would repair those. If not and there were an incident, they would, obviously, be subject to great penalties from PHMSA, and hopefully, everybody is aware of that.

Ms. Brown of Florida. What do you think would be our responsibility as we rewrite the law? Not the rule. Our responsibility as lawmakers as we move forward.

Ms. Quarterman. Well, I think you are doing the right thing to hold this hearing to ask questions about how the program is working and how we might improve it.

We are at a point in time when we have identified that 44 percent of oil pipelines could affect an HCA. It appears as though operators have assessed about 86 percent of those pipelines, so the vast majority--86 percent of all pipelines. Sorry. The vast majority of all pipelines, hazardous liquid pipelines, have been assessed at least once.

We are in the process of a reassessment. Forgive me for this analogy, but I think of it a little bit like a mammogram. You have the baseline, and then the next assessment shows you the change that has happened and whether there is cause for concern.

At the end of this reassessment period, which would be 5 years from the end of the first assessment, I think we will have a much better picture of pipelines in those high-consequence areas, and we should consider what the next step should be for the other areas.

Ms. Brown of Florida. You mentioned that DOT issued enforcement letters for 85 percent of all the integrity management inspections. What are the top three or four problems DOT has found?

Ms. Quarterman. The number one problem--and there were about four or five that were close to the top--was the evaluation of their leak detection capability to protect the HCAs. We found that operators had not done enough to ensure that their leak detection system was adequate. That was number one.

Shortly after that, we were concerned that they had not done an adequate analysis and documentation supporting their program. There was not enough to show that they had gone into great detail considering, for example, what is a high-consequence area.

We initially put out some baseline information about the locations of high-consequence areas, and the requirement was that operators would go the next step with respect to their particular line and the neighborhoods associated with it and look deeper and not just at the immediate vicinity; but if

there is, for example, a water intake point where, you know, liquid flows down that would flow down further away from the area that we have identified, they would do a deeper analysis of that, and we found some inadequacies in those kinds of analyses.

Third, we were concerned about the process that they used to qualify personnel for assessment results review. This is a key part of the analysis. They run the inline inspection tools or do hydrostatic tests or whatever. It is extremely technical analysis that is shown, and it is very difficult to determine what exactly you are being shown in one of these runs. We were concerned that the people who were reviewing the runs because we essentially put up this new requirement, and everybody in industry had to then get up to speed in order to do that, and some of the people were not as qualified as we might like to see them.

So those were the top three.

Ms. Brown of Florida. Last question.

If we find a company that is not in compliance, what kinds of penalties or fines do we have? What kind of enforcement mechanisms are in place?

Ms. Quarterman. We do have penalties that were instituted in the PIPES Act of 2006. I would say those penalties have not been updated according to inflation over time. At the moment, we are probably maxing out on the penalties at about \$100,000 a day, I think.

Ms. Brown of Florida. OK.

Congressman Young.

Mr. Young. Thank you, Madam Chairman.

My interest in this, of course, is the TAPS line, the Alyeska line. For the Committee, I am not going to ask her any questions. I am just going to suggest respectfully--and this is a creation of myself--that a little history, a little institutional memory, in this body does serve.

When we discovered oil in Alaska--when I say ``we,''' it was discovered in Alaska by the oil companies--at that time, we had to pass the Trans-Alaska Pipeline. In this Congress in 1973, the industry itself wanted to, in fact, operate the pipeline. They do not do so. Contrary to what some of your staff have said, they own parts of the pipeline, but they do not run it. It is a separate entity, entitled by itself to run itself, and it does run itself by itself. There have been three incidences in that pipeline where there have been, in fact, spills.

One was being shot at. It took them seven shots, by the way, with a .338 Magnum. The problem that arose then was the fact that they thought it was a terrorist attack, which was right after 9/11. It was an irate individual who just decided to do it. If we could have stopped it at that time, instantly, there would have been no spill at all, but the automatic shutoff valve did work. The oil did come through the bullet hole, and by the time they got done, there was a spill. That was not the fault of the pipeline.

In the recent one that we have had, it worked. There was a human error factor. There was a breaker that was forgotten to be checked. The oil that did spill at the pump station was contained, as it was designed. It worked excellently, and there was no environmental damage. I have to say that again because, according to the report I read from your staff, there was. In fact, there was not.

Thirdly, I take great pride in this pipeline. It was built in 1976. It was built in 3 years, and it has supplied oil to the United States of America. It has all gone to America but two tankers. This pipeline has been under scrutiny constantly, and to somehow tie this in with BP I think is piling on.

We have a lot of great Americans who work for BP, and for

some reason now, if you work for BP, you are a bastard. I am saying that is totally wrong. These are honorable people. The company may have done something wrong in the Gulf. I am not going to defend them in that area, but as far as the Alyeska Pipeline, I am quite excited about their record, and I know some people in this room who are going to testify later will say, Well, they have transferred people out of Fairbanks. Yes, they have. I do not like that, but in reality they are a business, and they have the opportunity and the responsibility to make sure that the business is run correctly, and they have not had any damages.

So let's not tie this Alyeska Pipeline in. They have supplied 17 billion barrels of oil to America--to Americans--to be utilized there, and they have run this operation extraordinarily well. I just want everybody to understand that. This company is dependent on itself. It may be funded by oil companies, but it is independent on itself, and that is the way it was constructed.

If you want to check the record, Ralph Nader called me the most powerful freshman Congressman in Congress because he didn't think I would vote for that, to have an independent agency run the pipeline and not the oil companies, themselves.

So I just want to remind people, when we start pointing fingers, make sure you point them in the right direction. This is not BP's problem. It is not a problem. This is a good pipeline. It has supplied us with 17 billion barrels of oil without any incident at all.

I yield back the balance of my time.

Ms. Brown of Florida. I ask unanimous consent that Mr. Young be permitted to participate in today's hearing and sit and ask questions of the witness.

Without objection.

Ms. Richardson.

Ms. Richardson. Well, after that, I will tell you. Welcome, Mr. Young.

Mr. Young. I always add a little bit of spice to any Committee meeting. I will guarantee you that.

Ms. Richardson. All right. Well, I won't speak to Alaska because I don't live in Alaska, and I haven't studied it, but I have been to the Gulf, and I have been studying that, and I don't think you can call it ``honorable'' at all.

Ms. Administrator, I just want to go back to my question and make sure we have your commitment on two things.

One, the raw data of all spills on your Web site today are perceived by laymen--I am not a chemist. I am not a biologist. I am not an engineer-- so, in my mind, they are basically unreadable--a bunch of codes--but it is not really clear. In fact, the only ones that can really be read are the incidences and spills that are referenced as ``significant'' or as ``serious incidences.''

It is my understanding that the Committee has brought this to your attention and that there has been a verbal understanding that you will make the changes and make sure that all of the spills and incidences which are listed on the Web site are readable in layman's terms and are clearly, obviously, available to this Committee on a regular basis; is that correct?

Ms. Quarterman. That is correct. The Committee has brought it to our attention that it could be improved. We appreciate those comments, and we will ensure that the data is accessible. The purpose of it is for the public to be able to review it and understand what it means, and if it is not doing that, we need to fix it.

Ms. Richardson. Thank you.

Then my last question is: It has also been brought to my

attention that, with your department, many of the regulations and standards that have been adopted don't provide a specific certain date that the regulations must be met.

Then, further, if someone in the public or even in my office, in a government office, contacts and wants to get a copy of a particular standard, they are told that they have to buy the information from an industry association, and that seems completely contrary. Specifically, what I am referencing are standards--when we were looking into the issue, we couldn't find the API Standard 1130. When we contacted your organization, the response was that staff had to purchase it from API.

Safety advocates have raised this concern with your organization on numerous occasions, including hearings in this Committee. They have been told that they have to purchase the document from the industry association. Needless to say, I think that is absurd. So I would also appreciate your looking into that and the information being available to the public, whether it be electronic or that we be able to get from your department.

Ms. Quarterman. We had talked about this a little bit at the last hearing.

The standards that you are referring to are industry standards across, for example, engineering organizations, and they are ones that are--there is a statute that requires--or encourages the government to use these standards. OMB encourages them to use it. It is not just a PHMSA issue. It is a government-wide issue. Any organization or government agency, regulatory agency, that oversees an industry has adopted these kinds of standards.

I agree with you that it would be more pleasing if they were available for free to anyone who would want to see them. They are not available for free. We will commit to looking at ways in which we might make some of the standards that have been adopted more available to the public, and we have done that in many instances by either explaining in detail what is in the standards or providing them at our offices for people to come and inspect them or having them available electronically.

Ms. Richardson. Well, it is my understanding my office was told to buy it from an industry. So we look forward to your updating and improving that system.

Thank you very much.

Ms. Brown of Florida. Ms. Quarterman, there have been incidents, to my understanding, involving both Alyeska and BP, and BP does own 47 percent of the company, and their budget and management decisions have to be approved. I don't know.

Do you have the information that you can get to the Committee on the incidents that have occurred?

Ms. Quarterman. Do you mean all pipeline safety incidences associated with the Trans Alaska Pipeline System?

Ms. Brown of Florida. Yes.

Ms. Quarterman. I think that we can do that to the extent that they are available.

The most recent incident is still under investigation, and we are in the process of an enforcement action with respect to that one, but as to any of the historic incidents, we can certainly give you information on those, and there have not been many.

Ms. Brown of Florida. And you said there have not been many?

Ms. Quarterman. There have not been many.

Ms. Brown of Florida. Well, we have found out from the Gulf we only need one. You know, one is just too many, and one can destroy the environment and destroy industry. So what we have to do is--we can't afford not even one.

Ms. Quarterman. I agree.

Mr. Young. Madam Chairman.

Ms. Brown of Florida. Yes, sir.

Mr. Young. Madam Chairman, may I suggest respectfully, the recent incident, what they are investigating, was human error. A breaker was not checked. That is what happened. Then, unfortunately, there is the double standard there. The breaker was not checked by a human being.

Again, though, the oil that was spilled there was collected as it was designed to do so. It has been built to do that in containment areas. This is a classic example of something that is engineered to do the right thing. That is why I am so defensive about the line. We built it. We designed it, and it has worked through two earthquakes, one an 8.8, and it did not have any spills.

Now we had this spill caused by human error that was, in fact, contained as it should be. There was no dispersement of any oil. So there was no accident in the pipeline, per se.

Is that correct, Madam Quarterman?

Ms. Quarterman. I am sorry. What is your question?

Ms. Brown of Florida. There was an investigation, is my understanding.

Mr. Young. Yes. The investigation is why the human error occurred but not on the pipeline, itself.

Ms. Quarterman. The investigation is ongoing.

Mr. Young. Yes.

Ms. Brown of Florida. Yes.

Thank you for your testimony and you will get back with us and answer those additional questions.

What I would like to do is to call up the second panel. We have a vote, or should we just wait until we come back?

Mr. Young. Madam Chair, start it because it will be 45 minutes, don't you think?

Ms. Brown of Florida. Let's call up--it is just one vote.

Mr. Young. One vote or two votes?

Ms. Brown of Florida. Let's have the one vote and then come right back. I thank you all very much, and the second panel, you can take your seat and we will get started. We can stand informally in recess, and we are looking forward to a lively discussion of the second panel. All right.

[Recess.]

Ms. Brown of Florida. Will the Subcommittee come back to order, please.

I am pleased to introduce our second panel of witnesses. First, we have Mr. Richard Kuprewicz, who is the Public Member of PHMSA's Technical Hazardous Liquid Pipeline Safety Standards Committee and President of ACCUFACTS, Inc.

We have Mr. Greg Jones, who is Senior Vice President of the Technical Support Division of Alyeska Pipeline Service Company.

And we have Representative David Guttenberg, who is the House Minority Whip of Alaska State House. He represents House District 8 in the area of Fairbanks, Alaska.

And we have Mr. Adams, Vice President of U.S. Operations, Liquids Pipelines, Enbridge Pipelines.

I want to welcome all of you here today and we are pleased to have you all here this morning. First let me remind each of you that under Committee rules oral statements must be limited to 5 minutes. Your entire statement will appear in the record.

Mr. Kuprewicz, you can start your testimony. Did I pronounce your name right?

Mr. Kuprewicz. Kuprewicz. But I have been called a lot worse for 40 years. But that is very close, thank you.

Ms. Brown of Florida. OK.

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TECHNICAL HAZARDOUS LIQUID PIPELINE SAFETY STANDARDS COMMITTEE
AND PRESIDENT OF ACCUFACTS, INC.; GREG JONES, SENIOR VICE
PRESIDENT, TECHNICAL SUPPORT DIVISION, ALYESKA PIPELINE SERVICE
CO.; THE HON. DAVID GUTTENBERG, HOUSE DISTRICT 8 - AREA OF
FAIRBANKS, ALASKA, ALASKA STATE HOUSE MINORITY WHIP; RICHARD
ADAMS, VICE PRESIDENT, U.S. OPERATIONS, LIQUIDS PIPELINES,
ENBRIDGE PIPELINES

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Mr. Kuprewicz. I would like to thank the Committee for the opportunity to comment this morning. My name is Richard B. Kuprewicz, and I am President of ACCUFACTS, Incorporated. I have over 37 years experience in the industry, and I have represented numerous parties within the U.S. and internationally concerning sensitive pipeline matters. I am currently a member of the Technical Hazardous Liquid Pipeline Safety Standards Committee representing the public.

My comments today focus on two major pipeline integrity management, or IM, issues and apply to both liquid and gas pipelines. One, changes are needed in reporting IM performance measures. And two, pipeline corrosion regulations are inadequate.

Given the many repairs, more public transparency is required in IM performance data gathering and reporting to assure this method is thorough and, more important, appropriate. This is especially true as more risk-based performance measures are applied by pipeline companies in both high consequence and non-high consequence areas.

The Gulf of Mexico offshore release tragedy clearly underscores what can happen when risk-based performance approaches step into the realm of the reckless and prudent regulation and check and balances don't come into play to prevent such tragedies.

What is missing in the area of IM performance reporting from PHMSA are summaries by type of repair condition; for example, for liquid pipelines immediate repair, 60-day, 180-day, and other; by kind of threat; for example, internal corrosion, external corrosion, third party damage, construction, pipe material, et cetera, actually found at each repair site, by State. Congress should require changes in IM reporting, as I have just summarized, and should also require PHMSA to recompile and restate the anomalies repaired to date, as I believe critically important hindsight will be gained by this effort.

PHMSA is also now taking a more active role in inspecting pipeline construction activities and has discovered very disturbing observations related to some new pipeline--poor manufacturing quality, poor girth welding and other construction-related activities that can seriously effect a pipeline's integrity and IM program over its life cycle.

Congress should assure that PHMSA has sufficient resources to perform these important construction inspections without harming other important efforts. All IM programs obviously should track and report to PHMSA any related new construction, introduced integrity threats, to assure that they have been properly rectified or are under control during the long lifecycle of a pipeline.

In reauthorizing the Federal pipeline safety laws, Congress should also take stronger action on reducing the risk that corrosion poses to the integrity of hazardous liquid and gas transmission pipeline. PHMSA has found wide variation and operators' interpretation of how to meet the requirements of pipeline safety regulations in assessing, evaluating and remediating corrosion anomalies. This raises serious concerns related to how consistent corrosion anomaly evaluations are and stresses the importance of modifying the reporting of IM

performance measures as discussed earlier.

It is clear that additional corrosion regulatory standards are required for pipelines both in high consequence areas and non-high consequence areas. For example, mandatory uses of cleaning pigs and avoiding over reliance on corrosion inhibitors that can become ineffective.

Some companies appear to be diluting their corrosion control programs to save money as they overly rely or misrely on IM inspections to catch such risks before failure. It is incumbent upon the pipeline operator to have corrosion and maintenance programs to assure corrosion is under control in all segments of their pipeline and not just rely on IM inspection. Congress should also require that special regulatory focus be directed towards the much higher rate selective corrosion, both internal and external, that can lead to pipeline failure well before the next IM regulatory reassessment, and it is not prudently handled correctly in current regulations.

Given the shortcomings identified in my testimony, it is too early to address the issue of modifying the IM minimum reassessment intervals required by Congress. The matter is especially important for gas pipelines where IM requirements in many areas are less stringent and cover much fewer pipeline miles than that for liquid pipelines.

I would especially advise that Congress pay special attention to gas pipelines, especially those capable of putting more tonnage of hydrocarbon into residential neighborhoods in a form that can cause greater destruction than many liquid pipelines.

Gas transmission pipelines have yet to complete their baseline assessments, have longer reinspection intervals and different special requirements for scheduling remediation reporting than liquid pipelines.

I thank you for your time.

Ms. Brown of Florida. Thank you.

Mr. Jones.

Mr. Jones. Chairwoman Brown, Ranking Member Shuster, and Members of the Subcommittee, thank you for the opportunity to appear to discuss the Alyeska Pipeline's Integrity Management Program. I am Greg Jones, Senior Vice President of the Technical Support Division for Alyeska Pipeline. My division includes engineering; health, safety and environmental quality; projects and security.

I have worked for Alyeska for 13 years. Before joining Alyeska, I served for 20 years as an officer in the United States Coast Guard. I am here representing the 1,600 people who operate and maintain the 800-mile Trans-Alaska Pipeline System, transporting crude from Alaska's North Slope to Valdez, where it is shipped to the West Coast.

Safety and integrity of the pipeline are core values at Alyeska and a top priority for every employee. Over the past decade we have continually improved our safety and environmental performance, with 2009 being our best year on record. Although we are proud of our progress, we know that we have to perform well every single day. Regrettably, we did have a significant incident recently, which I will discuss in a moment.

We are here today regarding the integrity management regulations that govern liquid pipelines. We have found the current pipeline safety regulations rigorous, comprehensive and appropriate. Federal regulations require a comprehensive corrosion control program. Alyeska's program is extensive and is monitored by PHMSA.

Our Integrity Management Program is also closely monitored by the Joint Pipeline Office, a unique consortium of 11 Federal

and State agencies that provide oversight of TAPS. Our program is subject to inspections by PHMSA. The most recent inspection occurred on August 2009. The inspection team's written exit summary included the following statement: The Alyeska Integrity Management Program document is well organized and addresses the important management system characteristics that are required for a successful program.

Our Integrity Management Program is focused on maintaining the integrity of the pipeline and protecting public safety and the environment. While Alyeska implements and complies with Federal standards, many internal procedures exceed these requirements. We monitor the pipeline through visual inspections, overflights and valve inspections; we conduct internal inspections using smart pigs every 3 years. The regulatory standards require runs every 5 years.

We are required to investigate pipeline segments that could affect high consequence areas when our data tells us there is a wall loss of 50 percent or greater. We actually go by a more rigorous standard of 40 percent. In addition, our corrosion control program includes numerous other elements. A cathodic protection system protects the below ground pipe from external corrosion. Other program elements include our valve maintenance program, river and flood plain maintenance and control. We also have an earthquake preparedness program, a leak detection system, and an over pressure protection system.

Should TAPS experience a pipeline discharge, we have worked diligently to be prepared to respond to an incident. We exercise our personnel and equipment on a regular basis through company and agency-directed drills and under the scrutiny of regulators.

Our spill response preparedness was demonstrated on May 25th, when during a scheduled shutdown of the system a breakout tank overflowed, resulting in a spill to secondary containment that surrounds the tank. There were no injuries and the spill did not escape into the environment. While the response went as required, we clearly find the incident unacceptable. We have done a full investigation into the event and are now working to implement recommendations to ensure that it will not happen again.

As I have outlined, our Integrity Management Program draws on a number of methods that we believe best protect Alaska's environment and keeps the pipeline operating safely and reliably. In Alyeska's 33 years of operations we never experienced a leak on the mainline pipe due to corrosion. We credit the skills and experience of our people, the current regulatory framework, the tools and strategies we use to protect the pipeline, and our aggressive attention to investigation and intervening whenever needed in order to ensure the integrity of TAPS.

I will be happy to answer any questions.

Ms. Brown of Florida. Thank you, Mr. Jones. I want to point out that Mr. Jones and Mr. David Guttenberg came all the way from Alaska. So I really, really do appreciate it.

And now the Honorable David Guttenberg, House District 8, Fairbanks, Alaska.

Mr. Guttenberg. Thank you, Chairwoman Brown, Ranking Member Shuster, other Members of the Committee and Representative Young, my Congressman. Thank you for the opportunity to speak with you today.

As you said, I am State Representative David Guttenberg and I represent House District 8, which is comprised of the west side of Fairbanks and goes all the way to the community of Cantwell, and the district includes the entire Denali National Park, including Mount McKinley, the highest point on North America.

I spent 25 years of my life working around the pipeline and oil industry. As a young man in 1974, I joined the Labors Union and went pipelining. My first job for Alyeska was with a clearing crew clearing the right-of-way where the pipeline was going to be built. Prior to that I worked on a seismic crew out of Umiat for minimum wage, 14 hours a day at 40 below temperatures, and that is not unusual but here it certainly is.

The next 25 years I worked for various contractors who worked for Alyeska, BP, Exxon and whoever else had a contract with the industry to build whatever was needed to be done. At one point I worked offshore building an island for development and exploration. My last job with Alyeska was in 1996, when we took Pump Station 6 offline.

I am here today on behalf of Alyeska employees that have contacted me with concerns of the safety and integrity of the pipeline, and these concerns they feel have been largely ignored.

My involvement specifically in this began in December of 2009 when I received word that Alyeska was planning to transfer a group of employees from Fairbanks to Anchorage. The proposed transfer raised alarms for me. First of all, for two reasons, they were good jobs and they were leaving my community. Secondly, I couldn't figure out what standard Alyeska used to determine that moving these personnel who were responsible for pipeline safety integrity 350 miles from the pipeline would be prudent and responsible. My initial thought is that it didn't make any sense. When something goes wrong, it needs to be checked on the pipeline. These are the employees who get to the problem, the problem and location quickly. The pipeline goes through Fairbanks; it is 350 miles from Anchorage.

When I began speaking out publicly, several Alyeska employees contacted me and confirmed my concerns. It was explained to me that many in the company shared my sentiment and attempts to express those concerns were squashed at the highest level by senior management who feared retaliation for going against the mandate of Alyeska's then President. At that point it became clear to me that Alyeska's open work environment was not working. Allowing poor decisions to go unchecked could have severe consequences for the State of Alaska.

Alyeska's predicted loss of almost 50 percent of the company's integrity management unit group if the company moved forward with a transfer. This is a long-term negative impact on Alyeska's Integrity Management Program, including deteriorating morale of remaining personnel, a significant loss of expertise and institutional knowledge, and the return to Alyeska's previous history of compliance problems with integrity management issues.

In 1997, under the direction of then Alyeska President Bob Malone, Alyeska transferred employees from Anchorage to Fairbanks to increase pipeline safety and enhance environmental reliability. This was the right move to make and it is difficult to understand how Alyeska's claim of synergy and efficiency justified reversing Malone's decision. Common sense and Alyeska's internal documents suggest that they are making the wrong decision on this one.

Alyeska frequently mentions its recent safety or environmental record when trying to reflect recent criticisms related to the management of its Integrity Management Program; for example, low accident rates. Alyeska's definition of safety refers to the prevention of bodily harm or fatalities to employees or contractors performing work. This safety attribute has little or no bearing on the likelihood of TAPS having a significant spill, which is the issue that brings us here today for this hearing.

For example, a pipeline operator could have an excellent work safety record because there is little or no maintenance being performed on the pipeline, while at the same time it is about to fall apart in 20 locations. The same logic could be applied to Alyeska's environmental record, which can have little or no bearing on the likelihood of a pipeline having a significant spill event.

Finally, I would like to address Alyeska's recent public commentary about emergency spill response capabilities in the first 12 or 24 hours.

Alyeska no doubt continues to have adequate employee and contractor support, but it is not the primary concern related to the transfer integrity manager and personnel. The Trans-Alaskan Pipeline carries an overwhelming majority of Alaskan State revenue and is an integral part of the U.S. Energy infrastructure. With a declining throughput, the line is no less important now than it was 30 years ago. Even through the declining input, the line is no less important now. However, the TAPS infrastructure is rapidly aging and problems are bound to occur. Now is not the time for Alyeska to skimp on pipeline safety and integrity lest we have a significant spill.

Thank you.

Ms. Brown of Florida. Thank you.

And Mr. Adams.

Mr. Adams. Thank you, Chairwoman Brown, Ranking Member Shuster, Chairman Oberstar, my Congressman, and Members of the Subcommittee. I am Rich Adams of Enbridge Energy Pipeline Company and appreciate the opportunity to participate in this hearing. I am Vice President, U.S. Operations for Enbridge Liquids Pipeline and have more than 20 years of experience working for Enbridge in various engineering, operating, and leadership positions with Enbridge's North America natural gas and liquids petroleum pipeline businesses.

Our liquids pipeline business unit delivers more than 11 percent of overall U.S. oil imports, stretching from Canada into United States refined hubs, delivering about 50 percent of the crude oil refined in the Great Lakes region. More information is included in my written testimony.

The pipeline integrity management regulations respond to societal expectations of safety and build on advances of new technology and pipeline operating experience. The result, a measurable significant reduction infrequency and severity of releases from liquid pipelines. This is a strong indication that Congress' passed mandate of a risk-based integrity safety reg regime is working, and while we are encouraged by this record, our overall goal is zero. Zero releases, zero injuries, zero fatalities, and zero operational interruptions.

To continue this encouraging trend, I urge Congress and the Office of Pipeline Safety to remain focused on a risk-based approach that has delivered this overall performance. The current regulations are extensive and recognize that safety starts with the design stage and continues with a broad range of operating, maintenance, reporting, inspection, and worker qualification requirements.

Reduction of risk considers both the probability of a pipeline failure as well as the potential consequence of such a leak. Congress was on the right track more than a decade ago in focusing regulatory and industry attention on high consequence areas to protect people and the environment. The focus imposed additional protective measures for pipelines at high consequence areas, or HCAs, regardless of whether a pipeline operations in a HCA or non-HCA area, comprehensive Federal regulations still apply to the entire pipeline regarding design, construction, operating, maintenance, and emergency preparedness standards. As such, we cannot agree with those who

suggest that non-HCA segments somehow receive little oversight simply because they do not fall under the integrity management plan mandate associated with HCAs.

The whole point of risk management is to aggressively apply our best engineering skills and science to determine the probability and consequence of a potential pipeline failure at any single point along a pipeline.

While only 40 percent of Enbridge's liquids pipeline system could affect an HCA, nearly 100 percent of the mileage has been inspected with internal inspection inline devices. So you might ask why wouldn't the industry just support an expansion of the integrity management rules beyond HCAs. We believe such a mandate would effectively take the industry back to a prescriptive, one-size-fits-all requirement that would abandon the entire science behind risk management, suggesting that the likelihood and consequence of a pipeline incident are essentially the same no matter where they occur.

Collectively, we have been successful at implementing a risk-based approach that directs additional resources to HCAs where a potential release would have the greatest consequence on the public and the environment.

In summary, I think the data shows that Congress, OPS, and industry have been on the right path in the current comprehensive pipeline safety rules and the supplementary Integrity Management Program implementation. When the overall record and trends are taken in context, we have shown noteworthy, continuous improvement in pipeline safety, leading to today's record that is second to none in transportation safety of petroleum.

This concludes my testimony, and I am happy to answer any questions that Members of the Committee may have.

Ms. Brown of Florida. Thank you.

The Chairman of Committee the Full Committee has joined us, Mr. Oberstar, and we want to recognize you for any openings statements and we are so happy that you are here.

Mr. Oberstar. Thank you. The Committee got disrupted at the beginning with a vote on the floor. I was delayed getting here working on other Committee matters, including our aviation bill. We are hoping to get some progress from the Senate in reaching an agreement on an aviation bill.

Ms. Brown of Florida. Well, Mr. Chairman, I just want you to know the whole country appreciates you all moving forward and the Senate moving forward, the other body. We need that aviation bill.

Mr. Oberstar. If we can get the Senate to move anything, including time of day, that would be an achievement.

I appreciate you holding these hearings and the participation of Mr. Shuster, but also I was having a conversation, as you turned to me, with Mr. Young, who was Chairman at the time he wrote the most recent pipeline safety bill, but I have been involved with this for at least 25 years, with pipeline safety, from the time that pipeline leaked gasoline in the City of Mounds View just outside my district. A 7-foot long crack in the pipeline leaked gasoline for hours until an automatic shutoff valve finally detected and cut off the flow. But by that time the volatiles had moved up through the soil to the surface, and because those are heavy aromatics they stayed close to the pavement surface. And at 2:00 in the morning a car driving along the street had a loose tailpipe that struck the pavement, the spark ignited the volatiles, the entire street erupted in flame, buckled, melted the pavement, and a mother and her 6-year-old emerged from the house to see what was happening and they were engulfed by flames as they emerged from the front door. Their father-husband took their son and went out the back door and they were the two victims,

but houses were burned, the street melted, trees burned. It was a horrific scene. Cause: Corrosion, corrosion that went undetected.

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That is what happened with the BP pipeline in 2006, corrosion. It went undetected. We had hearings on that issue in this Committee in 2006. 33,000 barrels it turns out spilled, most of it into a containment vessel but then it spilled over, 5,000 barrels spilled over that containment tank into understandably a contained area, but it was still on the ground and the volatiles just evaporated into the air. They are a hazard to the environment as well. It took three orders from the Office of Pipeline Safety to get BP to take the action they needed to take to correct that problem, and an order, and in fact to DOT's credit at the time, Secretary Mineta, moved the Administrator of PHMSA out, brought in a retired Coast Guard admiral, Admiral Barrett, to take charge of pipeline safety and bring to it the skills of a Coast Guard safety officer, his career had been in safety, and set the Pipeline Safety Administration right.

And then they had to order BP to remove that section of pipeline and replace it altogether. That is something good management should have done on its own; it should not have yaken an order. I have said this in all of the areas of safety under the jurisdiction of this Committee. There has to be a corporate culture of safety; safety starts in the board room. The role of government is to set standards that must be met, but the government doesn't run these corporations. Corporations have to have people in charge whose first concern is safety.

I grew up with understanding safety in an iron ore miners family. My father worked in the Godfrey underground mine. The lives of miners were at risk every day when they were down 300, 600 feet. Now they don't have methane as we have in coal mines, but you have the risk of cave-ins and failures of pilings, of support columns or they are using wood that isn't properly kiln dried and the mine can cave in on people, and there are many other hazards in the underground mines that require a corporate culture of safety. We had the Steelworkers Union that insisted on safety. They didn't have a mine safety and health organization until I was elected to Congress and I authored that legislation to create it.

The same with pipelines. Pipelines, we have nearly 3 million miles in America, they run through communities, in many cases communities built up around the existing pipeline, but that doesn't mitigate the company's responsibility to be vigilant and to take action and to watch over corrosion. That is the enemy of safety. Corrosion is the culprit in most of the pipeline failures.

And then response by organizations--I just want to ask this question, Mr. Kuprewicz, Mr. Jones, Representative Guttenberg, thank you for traveling all the way from Alaska. Mr. Adams, I was at the ceremony for Enbridge in Carlton in my district where I saw more steel pipe in one place than I have seen anywhere in my lifetime. It all looks good now, or then. We want to watch and see what happens to it after it has been buried for a while.

What do you mean by risk management? Mr. Kuprewicz, I will start with you.

Mr. Kuprewicz. Well, I think it embodies the concept of a corporate culture that knows the difference between speculative risk and risk based on sound engineering principles that don't violate the laws of science. If you assume--like an example would be in corrosion. If regulations have been written, let's say, for general corrosion, the corrosion rate is 12 mills per year, 12 thousandths of an inch per year, and you have selective corrosion like microbiological induced or influenced

corrosion and it is 200 mills per year, you are way out of line. And I think there is a lot of science and technology out there that everybody understands and most corporate cultures and risk management understand general corrosion. What we have found in too many instances that resulted in failure there has been a misunderstanding of what I call selective corrosion. And I believe the Minnesota event you described in 1986 was also an example of a selective type corrosion attack. And by selective corrosion it is a different animal. It can really--first of all, it isn't constant over time and it can change. A lot of the regulations and standards are written as if we have general type corrosion. Now I want to be very clear here there are companies who are way ahead of this curve. They understand this science isn't rocket science, it has been around for many decades, and they apply rational risk management, and if they believe they have selective corrosion they are saying I reassess at more frequent intervals. That is a long winded way and I am sorry.

Mr. Oberstar. No, it is very important, but the underlying issue is can risk management and in fact doesn't it slip into just a paper management based on historical records, previous experience, and if you have very few incidents then we are going to relax the oversight and relax the requirements. Isn't that an outcome of risk management?

Mr. Kuprewicz. Well, that can be an outcome, but I would say the more prudent pipeline companies, and they are out there, I want to be very clear about that, this science has been around and developing well for 60 years. They don't drop their guard, they don't make this assumption that it is a paper science. They will look at it and say, looking at our systems, we have different types of risk here. And while we need the paperwork to be sure that we know what we are doing, they don't drop their guard and they will look for signs. Now after enough times you can say I don't have selective corrosion of certain types, for example, but they don't drop their guard, it is a continual evaluation. So I would say the really good companies don't just make it a paper exercise it is an integrated process.

Mr. Oberstar. That is the concern I have and that is where we need the constant vigilance on management of risk, and in aviation there was a drift toward this kind of historical experience, will have confidence in if you have had a good record of management instead of the constant reporting and recordkeeping and day-to-day oversight of maintenance.

Mr. Jones, I will give you and Representative Guttenberg and Mr. Adams on it, and then I will stop at this point because other Members have questions.

Mr. Jones. I would look at risk management as a way of looking at the things you have to do, the likelihood of something occurring, of incidents happening and then of course the consequences if they do occur. So you are weighing priorities, and of course a robust integrity management program does exactly that. And we have that at Alyeska. The program--when we run a smart pig, we take a look at and we basically analyze the data and we determine which anomalies need to be investigated first and we follow that sequence in everything. We are also more conservative than the regulations and it has produced very good results.

Mr. Oberstar. Does that also include running cleaning pigs in addition to smart pigs?

Mr. Jones. Yes, it does.

Mr. Oberstar. That was the problem in 2006, that BP had not run a cleaning pig through that line and had allowed waxes and other corrosive elements to build up within the pipeline.

Mr. Jones. Well, my understanding from reading is that is

what happened. For Alyeska we run a cleaning pig every 7 to 14 days, and when we are going to do a smart pig run, we actually run a series of those ahead of the smart pig to make sure that we get good data.

Mr. Oberstar. Are those practices what you understand by and include in risk management, periodic, whether you have had a failure or not a periodic run of the cleaning pig through the pipeline and periodic on schedule of running a smart pig through the line; is that included in the risk management?

Mr. Jones. Correct.

Mr. Oberstar. OK, Representative Guttenberg.

Mr. Guttenberg. Thank you, Congressman. You are always going to have risk management no matter what you do, but my concern is when you take it out of the hands of the qualified engineers that we have on projects like this and put in budgetary concerns for a yearly budget cycle, it might influence something on a budget influence instead of what is the most efficient thing for integrity management and safety. So when we look at those things and are dealing with them in that aspect I think that should probably be--not be part of the review is have the budgetary influence overwhelming the engineering.

Mr. Oberstar. When you are operating in what is essentially a hostile environment--I understand that somewhat. We don't have as many months of hostility in northern Minnesota as you do in Alaska, but certainly understand a hostile environment--you need an increased level of vigilance, right?

Mr. Guttenberg. Yes, not just certainly for personal safety but for everything that you do, because little things turn into big things very fast, and in Alaska they are in your face all the time.

Mr. Oberstar. What was the significance of Alyeska moving personnel from checkpoints along the line out of those areas where they would be available for quick response and consolidating them into Anchorage?

Mr. Guttenberg. Well, I think that was the point to begin with why they were moved there in 1997 by then President Malone, is that is where the job is, that is where the response capabilities come from. If you can put somebody there immediately, you might not have a problem. But if you move them 350 miles away, it is going to take a lot longer to do the analysis and to get there and to figure out that if you were there 3 hours ago this would have never happened.

Mr. Oberstar. Mr. Adams.

Mr. Adams. Congressman, I think certainly when Enbridge and our industry talks about risk management what we are trying to do is we are trying to apply resources where they will have the biggest mitigation of risk. And I think we need to look at our facilities on a case-by-case basis. We have pipelines that have different risks. We have pipelines because perhaps the product that carry or the original installation practices that demand a lot more diligence around corrosion type issues. We have other pipelines that may run through a very populated area that have a very--that transport a very friendly product that have excellent coating, an excellent cathodic protection system that we focus on third-party damage perhaps.

I think even Congress, in applying what they have done in recent years, has looked at pipeline management, integrity management from that risk-based approach. If you look back some years ago, our risks were around third-party damage. That was the number one risk that pipelines had. There has been legislation, there is one called changes that have been enacted that have reduced that and overall risk and all aspects of pipelines have dropped, but certainly in that area it has dropped more than others. We think there are some things that

can be done to even enhance that further, but I think all in all that is the attack we need to take to mitigate the risk associated with pipelines.

Mr. Oberstar. Thank you, Mr. Chairman. I yield at this point.

Mr. Walz. [Presiding.] Thank you, Mr. Chairman. Mr. Shuster is recognized.

Mr. Shuster. I am going to let myself be passed over for Mr. Young.

Mr. Walz. Mr. Young is recognized.

Mr. Young. Mr. Jones, how are you picked for the job you have got?

Mr. Jones. I am picked for the job that I have because at Alyeska we have to be competent, we work hard, and we have very professional people, and actually as a leader you surround yourself with good people. That is what I have tried to do and----

Mr. Young. How are you specifically picked, you are now what----

Mr. Jones. You mean to be here today?

Mr. Young. Yes.

Mr. Jones. I am the head of the group that does our Integrity Management Program as the Senior Vice President of Technical Support, and Mr. Hostler asked me to come here.

Mr. Young. Who do you respond to, Mr. Hostler?

Mr. Jones. I respond to Mr. Hostler. He is the CEO.

Mr. Young. And he is picked by whom?

Mr. Jones. He is a BP employee.

Mr. Young. But not for Alyeska?

Mr. Jones. He is picked by the board, the board that basically oversees Alyeska, but he is a BP employee.

Mr. Young. I know, but what I am trying to get across, we set this up specifically so you are not dependent upon the oil companies. When you take that job, if you were to take that job you respond to the Alyeska board and that board is independent of the oil companies.

Mr. Jones. That is correct.

Mr. Young. And that is the way it is set up?

Mr. Jones. That is correct.

Mr. Young. Now in your statement you said you have never had a spill since 1976; is that correct? It wasn't--you know, I admit to two, the one being shot at and the other one the recent one. I think--when was that, that was last--4 months ago, 5 months ago?

Mr. Jones. It was May 25th.

Mr. Young. That at a pump station?

Mr. Jones. Pump Station 9.

Mr. Young. Am I correct it was a breaker, someone hadn't checked the breaker and the pump didn't work or something like that? Physically there was a person there?

Mr. Jones. Yes, there were people there and it was--we did have a failure of a circuit breaker that caused total power loss and that resulted in the relief tank overflowing.

Mr. Young. And the relief tank overflowed into a containment area.

Mr. Jones. That is correct.

Mr. Young. Now this oil that we pumped through that pipeline of 600 and I believe, David, you can tell me, 620,000 barrels a day now or 640,000 barrels?

Mr. Jones. About 640,000 barrels a day.

Mr. Young. Are there any additives added to that oil different than had been added before?

Mr. Jones. No, but what we are experiencing with declining throughput, we are having to deal with changing crude characteristics.

Mr. Young. It is a natural change?

Mr. Jones. Right.

Mr. Young. Now is that more corrosive?

Mr. Jones. It can be, yes.

Mr. Young. And In reality are you running your pigs more often because of that probably added corrosive factor?

Mr. Jones. Yes, we are. In fact we steadily had to reduce the period there that we are running our cleaning pigs because we are experiencing more waxing and everything as throughput comes down.

Mr. Young. You know we have come a long ways though, Mr. Jones, because I can remember the first time Mr. Chairman, Madam Chairman, when I was in this chair actually sitting in this room, I said that we were going to use pigs to go through the pipeline, and someone said, oh, those poor little piggies. Had no knowledge of what we were talking about, but that shows how far we have progressed in this business of pipeline and safety and what we do to find out.

The question, as Mr. Guttenberg has said, the movement of people that was not your decision?

Mr. Jones. The movement of people was a decision supported by the senior leadership team, it was certainly one that Mr. Hostler made but we basically supported as his executive team.

Mr. Young. Now was that a business decision or was that a safety decision?

Mr. Jones. It was a business decision and it did not affect safety.

Mr. Young. Now this is where I question--I happen to like the idea and I don't like to interfere with his private business, but when you say it doesn't affect safety, how do you justify that when the representative said you are 300 miles away. Did you move the pipeline operators from the stations or did you move people out of the Fairbanks region that were in management?

Mr. Jones. We moved people that were in the Fairbanks office. Their duties were principally office based. We still have our full complement of people. There are over 200 people on any given day that are spread throughout the pipeline that are basically----

Mr. Young. Do you have people on site. Let's say the question about 300 miles away, do you have people on site that can respond to the bullet hole?

Mr. Jones. Yes, we do.

Mr. Young. How soon?

Mr. Jones. Well, we have 69 people who are ready basically for immediate response, they are 24/7, you know both shifts, all the time.

Mr. Young. All right. The alarm system goes off because of lack of pressure or increased pressure at one of the stations, goes through the management arena, you have the whole computer board, I have seen it. I am in Fairbanks, how long do it take me to get to pump station let's say--what would it be, Dave, 6, 5?

Mr. Guttenberg. Well, 7 or 8.

Mr. Young. How long would it take me to get there?

Mr. Jones. Well, to go to Pump Station 7 you can drive.

Mr. Young. But the one that I can't drive is what I am leading up to.

Mr. Jones. Right.

Mr. Young. Between 1 and 3.

Mr. Jones. Between 1 and 3? Well, we would have the responders that are based out of 4 and we have some people at Pump Station 3, but we have a response base----

Mr. Young. You have people onsite to respond to that.

Mr. Jones. Right. We have them at all active pump

stations. They all have personnel and----

Mr. Young. You have them in all active pump stations now?

Mr. Jones. Correct.

Mr. Young. And when you say active, the ones that are not active they have been shut down because of a lack of need of oil or what is that?

Mr. Jones. Well, yeah, as throughput has been coming down we don't need the same pumping capacity. So again for business reasons we take out of service the stations that we don't need.

Mr. Young. And lastly, the Chairman mentioned this, Mr. Oberstar, the illusion of what happened with BP was they were collective lines, weren't they, that had the corrosion in them?

Mr. Jones. Correct.

Mr. Young. And they have been replaced?

Mr. Jones. Right now----

Mr. Young. That has really nothing to do with you does it?

Mr. Jones. That is correct. I was going to say, I don't work with them.

Mr. Young. You don't work with them, that is a different unit?

Mr. Jones. Correct.

Mr. Young. And this is Alyeska and not the collective pipelines?

Mr. Jones. That is correct.

Mr. Young. I am out of time. Thank you, Mr. Chairman.

Mr. Walz. Thank you, Mr. Young. I said always with the Chairman and with Mr. Young here I feel like I should pay tuition for the lessons and the learning I get. And I want to commend Mr. Young. I think when he talked about his vision of having Alyeska having a separate entity was visionary, was wise in that. I think the point I am trying to get at is since that time of that inception has there been a morphing, a loss of that autonomy? That is what I am trying to get at. I certainly don't want to pile on, I don't want to make the assumption, but I think it is a fair assumption. Alyeska is a for-profit company, correct?

Mr. Jones. That is incorrect. We are not.

Mr. Walz. It is incorrect. So you make nothing then. The issue is to stay there. So the autonomy issue of having these experts from BP and things is to bring in their expertise but not to necessarily have day-to-day say over the pipeline operation?

Mr. Jones. Well, they are one of five companies that comprise our board, and so they could not dominate the decisions even if they wanted to. We are an independent consortium. We run our company, we have a distinct culture. Our employees are uniquely Alaskan. In fact we are a very diverse company, we hire 20 percent Alaska Natives, the laborers and crafts that work on our pipeline actually choose to want to come work for us due to our safety culture. So we are very distinct. We are proud of all the employees.

Mr. Walz. I want to get at this point. I think Chairman Oberstar and many others, and yourself, Mr. Jones, with your military history, and I spent about a quarter century as a senior enlisted soldier. There is culture of safety in risk management. It is the air we breathe. I think the Chairman is right, it starts at the top, it starts as a culture. It starts being engrained in every decision that is made. And I just want to ask you, Mr. Jones, if you can see why some people were concerned, the statement that out of the Fairbanks paper November 17th of last year where you indicated--and this move we are talking about, movement of employees, and am I right there were integrity management employees that were part of this move?

Mr. Jones. Yes, sir, there were.

Mr. Walz. OK. It said all support groups should be looking at Valdez in addition to Fairbanks and asking what the business purpose is for the staff to be based at these locations, Jones wrote. The bias needs to be in favor of them working in Anchorage unless there is a compelling business case to the contrary. Is there not room also for this idea that there is not a mutually exclusive delineation between safety and the smooth running of the company and of the pipeline; why stressing the business case on this as the sole purpose?

Mr. Jones. Well, we were talking specifically about people that are based in offices, we were not talking about our field-based people. And so we had an opportunity to consolidate office buildings there. We were paying for almost 60 percent more space than we were utilizing. And so we--and we had also been involved in a centralization effort back towards Anchorage since 2002. This was just a continuation of that effort.

Mr. Walz. So the 1997 decision in your opinion was wrong or the situation changed since that time to warrant a review of policy?

Mr. Jones. I would say the 1997 decision was right for that time. Today we are in a different business environment with throughput declining 6 percent every year, so we need to be as efficient as we can.

Mr. Walz. So this was Alyeska and their board's decision alone. What input, explain to me so we can explain to our constituents, do BP or the other owner companies, what input do they have, sign off, budgeting, things like that, where do they have a role in this?

Mr. Jones. Well, we have an approval authority guide that specifies what levels of authorities and everything that we have as officers of the company and then what things that we have to send to the board for approval. But in this particular case for the office that was an Alyeska decision and it was supported by the senior leadership team.

Mr. Walz. OK. I want to go to you, Mr. Adams, and ask on this. Where are your integrity management personnel placed? Alaska is big, real big. North Dakota is pretty big, and your pipeline operations. Where are your integrity management people placed? Do you centralize that location?

Mr. Adams. There is some centralization. We have many of our integrity management people certainly at higher levels and technical levels actually out of Edmonton, Canada. They provide some overall support. And then strategically based throughout the system within regional areas we do have some integrity management folks. We do have field folks that have responsibility for some parts of integrity management, things such as cathodic protection systems and those sort of things, and they are on the pipe end themselves, via the technician level.

Mr. Walz. OK, I just have one more before we move to Mr. Shuster. Talking about this May 25th incident, and Mr. Young did a good job of elaborating to us and I think there are some positives in this in containment. One of the questions--and we are seeing this again. I think we would be remiss when one of my colleagues said there is nothing, what is happening with BP in the Gulf, that has relationship to this. I think there is in terms of response and in terms of response plans. I know those best laid plans and I am glad to hear--and one of things, Mr. Jones, you talked about that they gave you flying colors on your document when they looked at it. It is still a document, and I want to know what the indication is on the ground.

My question is the workers that responded to that May 25th incident, do you have a plan for long range watching their health concerns? Is there anything we should be concerned about of vapors, of contact, with was released or anything like that.

Mr. Jones. Well, we do have a plan where we would monitor that, but in this particular case we kept our personnel away from the area until the volatiles were able to essentially flash off. That is one of the things you do in a response, is you look at the hazards and we keep our people out of harm's way.

Mr. Walz. Will there be a follow-up on those folks to see if there is a cohort of these folks who responded to this thing, if they develop any abnormalities or health conditions?

Mr. Jones. Well, we certainly would, but we were very careful, we did atmospheric monitoring to make sure that we did not put our people in harm's way.

Mr. Walz. Last thing I would say, Mr. Guttenberg, would you respond on any of these that you maybe have a difference of opinion on these questions that were asked as this applied?

Mr. Guttenberg. Well, the placing of personnel is a key part of this equation that is ongoing for me. If you have agency people that need to respond with other agency people, they need to be in proximity to them, but the integrity management people that need to be in the field or in proximity to it that is very important. And I think that is a key to what is a concern for a lot of employees internally. Think there is something wrong, we have a difference of opinion, we are the people that do--they are the people that do the work. And the senior management made a decision that they felt was not in the best interest in the safety and integrity of the pipeline.

Mr. Walz. You stated, and I will end on this, that there is a culture of folks--I have looked at some these from screen names--I know for protection of integrity, afraid of spill, and some of these folks have written to your and some of the names have come out there. Is there a culture that they fear retribution on this? I know in a military setting that Mr. Jones is familiar with, and everyone else, is that anyone can call a ceasefire, anyone call a safety violation. You can shut down an operation from the lowest private to the general based on that. Do you feel that is not present in this operation?

Mr. Guttenberg. Well, I am kind of the cynic when it gets to the top anyway. My history in construction is you sit in a meeting where they say priority is top and the most important thing and you can stop it right now. But when you get to the point when you have to do something, it has to get done. But Alyeska does have a good history, they do have a good dialogue with employees and project employees over the years, but I am not in those offices watching and witnessing what happens.

Mr. Walz. OK. Well, I thank you all.

Mr. Shuster.

Mr. Shuster. Mr. Jones, first of all, I just want to point out based on what the Chairman said and Mr. Walz about your military background, you are a former commander in the Coast Guard, which I think brings great knowledge and that culture of safety to bear on the organization that you work with and work for.

I understand that Alyeska has a major maintenance shutdown, is that accurate?

Mr. Jones. Correct.

Mr. Shuster. And how significant is that to the operation, to the safety and to the integrity plan that you have in place?

Mr. Jones. Well, it is very significant. We have been actually doing two major maintenance shutdowns per year where we may do valve work, we may do piping work. And so it is usually major work to where we have to actually be able to isolate a valve or piping from pressure, which is why you do the shutdown, but it is all part of our overall effort for integrity management.

Mr. Shuster. As an event is it one of the most significant

things you do, those two shutdowns all year?

Mr. Jones. It is a big event and we do tremendous planning to make sure that we can do that safely.

Mr. Shuster. When will that occur?

Mr. Jones. The next one will be July 31st.

Mr. Shuster. And so I would imagine you have all hands on deck?

Mr. Jones. It is all hands on deck.

Mr. Shuster. Everybody is working?

Mr. Jones. From top management right on down. It is a serious thing.

Mr. Shuster. I want to point out to the Committee that sometimes in Washington in general there is a disconnect on what goes on in the real world and what goes on in Washington. I would have hoped that we would have taken that into consideration and maybe brought you here after the major maintenance was done, so you probably have spent a number of hours preparing, researching to be before us here today. So when we talk about here in Congress a culture of safety it needs to be start here also in Congress. So again I would hope in the future that the Committee staff and the majority would take those kind of events into consideration because taking you away, being the Senior Vice President for Technical Support, you probably have a lot to do with the maintenance coming up and here you are in Washington when you would better serve the safety culture and the culture of safety back there in Alaska. I just want to make that point.

The question, back to the moving of the staff, I just want to put into the record, ask unanimous consent to put in the Joint Pipeline Office of the Federal-State organization that oversees, has oversight up there in Alaska, put out this letter on--I don't know the date--July 14th and just one paragraph, to read that ``We consider Alyeska's transfer of integrity environmental staff from Fairbanks to Anchorage is a business decision because it does not involve first responders.''

So I would like the entire letter to be in the record to make sure that we have that because as I think it has been pointed out a number of times this is a business decision, it doesn't effect safety. And with technological changes from computers to monitoring devices to the transportation system, you don't always--in a business model you have got to make decisions to make sure you are efficient. I want to point out when you say nonprofit I think a lot of people think you don't make any money. But a nonprofit has to have more revenue or it should have more revenue than it does expenses or it is going to go down the tubes or you will come to Washington, D.C. And ask for us to bail you out. We need to make sure it is on the record that people know that you have got to be self-sustaining. So you have got to have a positive revenue flow over expenses.

Also, we wanted to ask how does Alyeska spending--how much do you spend annually on your integrity management activities to comply with the Federal pipeline safety laws and regulations?

Mr. Jones. Well, since 2005 coming up to present, we have had a steady increase in the funding for our Integrity Management Program. 2005 expenses were right around \$45 million total. And then leading up to today where it will be a little over \$60 million.

Mr. Shuster. Do you exceed the Federal standards, the Federal requirements, safety requirements?

Mr. Jones. Well, you know, I don't have a breakdown of that, but that is, you know, comprehensively everything that we are putting into the Integrity Management Program. The program is very effective, and, you know, we can see that also in our

performance.

Mr. Shuster. One final question for you.

Have you ever had a leak on the 800-mile pipeline that was due to corrosion?

Mr. Jones. No, we have not.

Mr. Shuster. If I could, I will ask one final question of Mr. Adams.

In your testimony, you claim, in the effort to strive towards the industry goal of zero releases, zero injuries, zero fatalities, no operation interruptions, that Enbridge holds managers accountable for those performance measurements designed to meet those goals during their personal performance evaluations.

If somebody fails to hit those goals, what actions do you take to rectify this?

Mr. Adams. Certainly, it depends on the position, but it is incorporated into our overall performance in terms of our bonus structure's pay for employees, and it depends on the level of the organization. Certainly, as you get to higher levels within your organization, there is a bigger impact on that compensation related to safety performance and pipeline integrity performance.

Mr. Shuster. I certainly think our goal should be zero fatalities, zero injuries. We certainly want to strive to do that. It is my view, though, that we are going to have human error and the possibility of mechanical breakdowns in striving for that goal as we should do; but I think the only way, realistically, that we can get to that point--and in talking to a company that has a stellar safety record--is you just don't do it. That is the only way we get to zero fatalities. It is the only way we get to zero injuries, unfortunately. I mean would you agree with that?

Mr. Adams. Absolutely. I think, traditionally, industry is looked at in terms of safety overall, a pyramid. If you get rid of the small issues, then you can eliminate the big ones in the long term. I think that conventional thinking has changed a little bit as a result of BP and what has happened in our own company with the issues that we have had. What we find is that any breakdown in the management system anywhere along the way--I think Congressman Oberstar mentioned that senior management in the boardroom has to believe in it, but every single one of your leaders within the organization has to believe in it, and when you get a breakdown at any level in that organization, you can have an issue.

I think we, as an industry, and everywhere can get to the point where we can't blame anything on human error because, if our management system works, we have those people trained. We have the right people in the right place doing the right job.

Mr. Shuster. Well, I just thank both of you for being here--all four of our witnesses--but these are two great examples of companies that have cultures of safety.

Again, I just want to reiterate that I hope we on the Committee here in the future take under consideration when a pipeline has a major maintenance shutdown, that we bring them to Washington after they have done this major maintenance safety situation that they are going under right now and not drag them down here to Washington to take their eye off the ball on safety.

So thank you very much.

Mr. Walz. Well, I thank the gentleman.

Also, though, I take my responsibility of oversight seriously. Maybe the gentleman can arrange for us to get to Alaska and make it easier for Mr. Jones and to make sure we are doing our job.

Mr. Shuster. I think Mr. Young has made a standing offer,

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and Mr. Oberstar has, I think, participated many times in that trip up to Alaska to see it firsthand. It should be done by all Members.

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Mr. Walz. We really appreciate it. I think there is little doubt that this entire Committee wants, as I said, to be able to move the petroleum that powers our country, at the same time doing it safely and protecting our workers and the environment.

The one thing I would bring back is this move of employees, though. I want to get at the decisions that were made in this because Alyeska asked its engineering director and the engineering integrity manager, who supervises the Fairbanks employees, to review the risks of moving integrity management personnel to Anchorage, which is exactly what was done.

They generated a report, and the findings--and I quote--stated: There are significant safety and integrity risks associated with movement of the current IM teams to Anchorage.

What overrode those inputs? I would think the engineering integrity manager and the engineering director would be pretty heavyweights in the decision on this. What was the decision then as it was being balanced out, Mr. Jones, to decide to do that?

Mr. Jones. Right. Well, of course, this was not the only consideration, you know, that we looked at.

In the report, they did not have any--we didn't ask them how to mitigate measures or to look at things, and when we went through our analysis, we had lots of discussion. We involved some of those engineers in discussions, and what we came up with was a balance to where we left some people who definitely had more of a role in the field. We left them in Fairbanks--that was three of the engineers--and then the people who had essentially office responsibilities were the ones who we brought in to Anchorage.

I had a conversation with one of the authors of that report just last week, and we talked about this issue. He has assured me, in how we have handled this, that we do not have a safety or integrity problem on the pipeline.

Mr. Walz. Would that person be willing to state that to us for the record and provide that to me?

Mr. Jones. Well, I can't speak for him, but based on what he told me, I would think he would.

Mr. Walz. OK. I would like to see if we can follow up on that to get these people who wrote this report. I would like to see if they have changed their position from this, and you are stating that they have. I would like to have them say that, if that is OK.

Mr. Jones. Just to be clear, I am stating that the integrity management manager, who was one of the authors of that report, has told me that.

Mr. Walz. Very good.

Mr. Shuster hit on this, the \$60 million on compliance and safety. Is that a greater percentage of your budget or less in terms of what you put into this? You stated that the number went up, but I think it is important in the context of things. Is maintenance being deferred because it is OK to do that and that the maintenance didn't need to be done at that time or is it being deferred to keep the costs down?

So Mr. Shuster talked about the \$60 million. It sounds like a lot, but it depends on how big the pipeline is. It depends on how much needs to be done. It depends on what percentage of the budget that is.

Are you increasing funding on compliance and maintenance in terms of your overall expenditures?

Mr. Jones. We have been on our, what we call, baseline expenses. It has been relatively flat. You would have to look at individual components.

The bottom line is we fund the essential work, and so we prioritize it, and we use that risk-based approach. That was one of the first questions that we had. So we always make sure that we go after the safety and integrity work. That is paramount, and it gets our utmost attention. We also know that if we had to go back for additional funding from the board in order to do that work that we could do so.

Mr. Walz. The last thing I would ask:

Is there overregulation on pipelines? Is there overregulation? Are we stepping in there? Are we hurting your ability to operate by having too much regulation? I hear this a lot. There is too much government. There is too much regulation. There is too much cost to you or whatever. Is there too much? I will ask each of you, if you can. I know it is subjective, but I would like to hear how you would respond to it.

Mr. Kuprewicz. Do you just want to go down the line?

Mr. Walz. Yes.

Mr. Kuprewicz. No.

Mr. Walz. OK.

Mr. Jones. What we look for are regulations that provide a very clear target, that are not moving, and that also get consistent application and enforcement of those clear targets. So, to the extent that regulation can do that, then, you know, we will take that on. We are not afraid of strict standards. You know, we understand that, but we need things to be very clear and uniformly enforced.

Mr. Walz. Are they that way now, in your opinion, Mr. Jones, or not?

Mr. Jones. Well, there are issues. You know, there are definitely things that can be worked on.

Mr. Walz. OK.

Mr. Guttenberg. Thank you.

You know, my legislative career is similar to yours. One of the things, the caveats, that I put in is that it has to work. In some hearings, when people have come in and complained about being overregulated, some of my colleagues from the other side of the table have said, ``Give me an example.'' ``Tell me what the regulation is that is in the way or too cumbersome.'' I don't see the answer, and I sit on the Reg. Review Committee in the legislature, and I haven't witnessed a lot of it. So, if they have something, they should come forward and be specific about it.

Mr. Adams. My comments would mirror, certainly, Mr. Jones'.

I would just add that I think there are some areas--and I mentioned them briefly--where I think we could use some additional regulation, and that is really around third-party damage and in some of the exclusions that exist out there, through municipalities or whatever, and I think that is certainly an area that we would like to see looked at from this body.

Mr. Walz. Great.

Mr. Shuster, do you have any follow-up? Then we will see if the Chairman has anything.

Mr. Shuster. Just on the third party, can you elaborate a little more on that?

Mr. Adams. Yes.

What exists out there--there are a number of different One Call-type programs from State to State, and there are certainly some variations.

Mr. Shuster. Speak into the mike more.

Mr. Adams. Yes.

There are a number of One Call Systems that vary from State to State, certainly, but within those, from municipalities in some cases, there are exemptions given to certain contractors

that are actually digging out there that aren't required to utilize those One Call Systems. From an industry perspective, or at least from an Enbridge perspective, we would like to have those exemptions eliminated.

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Mr. Shuster. And why are they exempted?

I mean, from a commonsense standpoint, if I am a contractor--well, I just--there was a point a couple months ago when I was digging up trees in my backyard. I made the call because I didn't want to make the mistake of hitting a gas line and blowing myself up or something like that.

Mr. Adams. Yes, I am not sure why those exemptions exist.

Mr. Shuster. OK. Thank you.

Mr. Walz. Chairman Oberstar.

Mr. Oberstar. Yes. Thank you, Mr. Chairman.

I thank the witnesses for their responses to the previous questions. I want to come to Representative Guttenberg.

These passages in your statement are very troubling to me, not troubling that you said them, but troubling about the condition of safety, that the move of personnel, which Mr. Jones described as a business decision and you described as a cost-saving measure, the company said would result in a onetime savings of \$4 million, but then you go on to say that it would significantly decrease work efficiencies, increase travel costs. It would be the--and you point to an internal review by Alyeska that the loss of almost 50 percent of the company's integrity management group would occur if the company moved ahead with the transfer and that it would have the effect of deteriorating morale for the remaining personnel and in a loss of expertise and institutional knowledge and would return to Alyeska's previous history of compliance problems with integrity management.

That seems very much to be at odds with what Mr. Jones is saying, trying to sort of brush this over as just a little business decision. This is substantively more than a business decision, right?

Mr. Guttenberg. Thank you. That is my feeling as well.

I know the report that Alyeska had done, which was referenced by the Chairman, is where some of that information comes out of. The morale and the loss of employees is--you know, they moved people from Fairbanks to Anchorage. Now they are moving them back. A certain number of them decided not to take that move. I know they were looking for positions at other places. Up until today, it has still been an ongoing situation, but if you are an employee and if you are a highly skilled, trained, educated, experienced engineer, working in integrity management, and you see a situation in front of you that says, ``I am not going to be able to do my job if I move to Anchorage, the way it is defined for me in looking at what I need to do,'' then doing this job is no longer ever going to be satisfactory because I am not going to be able to do it. I am going to have to have more travel time. That is the increased cost. Then you are going to have a loss, and I think the institutional memory cannot be undervalued.

Mr. Oberstar. What is the travel time from Anchorage to these outposts along the pipeline where personnel were stationed?

Mr. Guttenberg. Well, if you were driving, it would be about 8 hours. If you were flying, it would be an hour plus.

Mr. Oberstar. But you wouldn't be driving anyone to respond to an oil spill. You would fly them up there.

Mr. Guttenberg. Well, that is not my decision. That is Mr. Jones' decision, but how you get there, whether you go by Glennallen or anywhere in between or any of those small communities or even north, you know, there might not be an airstrip for 20 miles.

Mr. Oberstar. That is the other question of mine.

Are there airstrips close to those checkpoints where personnel were located?

Mr. Guttenberg. Well, since the construction of the pipeline--and I, you know, was involved in some of that--there are periodic airports and old construction camps all along the pipeline.

Mr. Oberstar. Mr. Kuprewicz, you have been involved in pipeline safety for a great deal of your career.

What do you think about the effect of moving personnel with the skills, the expertise, and the institutional knowledge, as Representative Guttenberg stated, and the effect on vigilance and response time and safety in this environment of the pipeline in Alaska?

Mr. Kuprewicz. Well, first of all, you need to understand the history of Alyeska is they have developed issues that have set some of the original technology because they had serious corrosion risks and problems. They didn't have leaks, but they had corrosion, and those are well publicly known issues.

Mr. Oberstar. Yes.

Mr. Kuprewicz. So they have advanced the field in some of those areas, which are real important, so I don't want to take that away from them.

The other side of it is, as you tend to create chaos in an organization, you have to be real careful with this because there is importance to things likes institutional memory, and that is one of the roles of government--to be sure, I think, that you don't reinvent the wheel. Some of the regulations should set certain minimums, and so you have got to be careful with all of this chaos, if it is real, and I am not up there, so I can't say how this has affected that organization, but you did lose 50 percent of your group.

Now, what was the group, and what were their skills? Those are the kinds of things.

When you create this kind of chaos for a technically cultural-based knowledge skill required, you want to be real careful with that. It doesn't mean you don't have to make those decisions, but you want to be real careful. In some cases, I have seen it in other companies. They have missed that. They have missed that complication with the confusion that they can cause, and they have had to reinvent through various field errors--and some of them not always catastrophic, but they have had to reinvent their learning curve.

So I would just caution folks on that. It is an issue. It is an issue your folks are pursuing. You need to understand that and be comfortable with it. That would be my advice.

Mr. Oberstar. Thank you.

Mr. Adams, what is Enbridge's policy on the response and stationing of personnel? This is a very long pipeline that goes from Athabasca in northern Alberta, all the way to the Headwaters of the Great Lakes.

Mr. Adams. Yes.

What we have is we have our own emergency response personnel. Effectively, those emergency response groups are spaced probably 3 or 4 hours apart within our pipeline system. So, really, we can get people to the site sooner than that because we have technical-type people that are on call, but the emergency response crew, with equipment and certainly boom and recovery equipment, can be there in a 3- to 4-hour period typically.

Mr. Oberstar. Three to 4 hours apart by what measurement?

Mr. Adams. By initial reporting, reporting of the leak or the area of the leak. In some instances, that can be a phone call from a third party. It can be our own pilots or aviation observing that there is a leak along the pipeline or an issue.

There are a number of different ways we can get notified through our control center.

Mr. Oberstar. When the Koch Pipeline burst near Little Falls in Minnesota, it was a person driving by, going home from work, who saw this black geyser shooting into the air alongside Highway 10. He was astute enough to realize that they don't have oil. There are no oil wells there. It is not likely that oil just spurt out of the ground, and he realized it and smelled it.

He called the county sheriff's office, and the sheriff's office then had a phone number for the pipeline company, called ``Pipeline Company.'' Then they called their office in Oklahoma to shut off the valve that controlled that segment of the pipeline.

You know, the time frame was relatively short, but I just wonder what would have happened if that had been the dark of night and no one had seen that going. I asked that question of Koch, and they said, Eventually our sensors would have detected a decrease in pipeline pressure, and eventually that would have caused a shut-off.

Is that what you are talking about? Are those the kinds of automatic valves that are periodically located along the pipeline?

Mr. Adams. Yes. We certainly have valves along our pipeline system, and in recent years, we have had programs where we are installing additional valves, automatically operated valves, on each side of the sensitive areas.

Mr. Oberstar. But, that 3 to 4 hours, is that response time from the time someone hears or knows of it and is on scene?

Mr. Adams. Yes, that would be getting people on scene.

Mr. Oberstar. By driving? By flying?

Mr. Adams. By driving, typically, in most of our areas.

Mr. Oberstar. You measure your response time in hours on the road, driving?

Mr. Adams. Yes, a response to have people physically at the site. Certainly, our response time from our control center can be almost instantaneous, and our large leaks are typically detected by our control center personnel. They have enough experience and training that, with usually a leak of any size, they can view that there is a change in the operating system, and there are provisions that, if there is uncertainty, they have to shut down within a period of time, and that would include the closing of automatic valves.

Mr. Oberstar. The valve structure that you have on your pipeline and the frequency of valves is that there are more in urban settings and fewer in rural areas. Is that by your standards or are those by the Office of Pipeline and Hazardous Material standards or by State standards or what?

Mr. Adams. Yes, there are some standards in place, but we go beyond those standards and set our own standards. We have a risk management group that evaluates our pipeline flows. It evaluates the terrain that the pipeline is going through. Obviously, if you are on flat terrain, if there is a leak that drains up, even if the pipeline is shut down, is relatively small. If you are in a large area where there are large hills, you probably would want to install more valves. You would want to install valves on each side of a river, for example. If, indeed, there were a break in the river, you would close those valves.

So it is very dependent, again, on where the pipelines run and the terrain, and we try to be prudent and, again, looking at where we can minimize the impact if, indeed, we did have a leak.

Mr. Oberstar. Now, Mr. Jones, you said in the course of your testimony that there was no effect on people of that

spill. Yet the reports that we have are that an employee reported smelling crude, so somebody had to be affected by it. Clearly, somebody was--at least one person, maybe more--and volatiles are carried by wind, and they go considerable distances.

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Mr. Jones. Well, that is true that volatiles do travel with the wind. I am not familiar with that particular case.

What I do know is, in responding to that incident, we made safety and the concern about those vapors basically boiling off--you know, since it was a pool in secondary containment, it was important to us to not let our people, you know, get in there, and we waited a considerable amount of time. Then we did atmospheric monitoring, and we made sure that our people were outfitted in the appropriate gear before making site entry. That is a standard part of our response procedures. We actually had a very excellent response in this. It was very timely.

Mr. Oberstar. Well, as to the cost-saving measure or business decision you made to bring personnel from the various locations on the pipeline into a consolidated area and to reduce the number of personnel, what is your time frame of moving personnel on scene?

You heard what Representative Guttenberg said. What is your plan? Do you fly them? Do you drive them? Do you use a fixed-wing or a helicopter to get people on site? Have you done a risk management evaluation of time frames and moving personnel on scene in case of failures?

Mr. Jones. We actually do extensive planning to know how long it takes us to respond to certain sites, and we have----

Mr. Oberstar. What is that time?

Mr. Jones. Well, it varies depending on where you would have a spill, but we actually get into looking at all of the sensitive areas, and we develop very detailed plans to know exactly what we would need to do for a given scenario.

One thing I need to correct here--and this is where I think there is some confusion--is that the people that we moved from Fairbanks to Anchorage were office-based. They were not part of our initial response team that we have. We have not changed any of our response capability for first responders. We have 69 people, as I said earlier, 24/7 that are ready to go immediately. They are dispersed throughout the stations, along the pipeline and also at the Valdez Marine Terminal. I would rate our response capability as ``best in class.''

Mr. Oberstar. So how many integrity management personnel does that leave on the pipeline on scene at various checkpoints?

Mr. Jones. We don't have integrity management personnel at the pump stations. We never did. These personnel were in the Fairbanks office. There are about 20 total that are in the group. We currently have six vacancies. We have interim measures in place to cover those duties, and we are going through hiring and are actually doing interviewing right now. So I am very confident that we will replace the talent gap that we have, and we will not have safety or integrity impacted.

Mr. Oberstar. So your plan is to fill those positions and bring it up to full steam.

Does that satisfy you, Representative Guttenberg?

Mr. Guttenberg. We will just have to see, at the end of the day, who is there. You know, where it hits the road is when something happens, and then you discover whether there were competent people in place who could actually do the response, not just the first response, but the secondary response to assess and take action on a spill or a problem.

Mr. Oberstar. Now, your constituents in the area of the pipeline where they have seen spills, are they comfortable with these management decisions now?

Mr. Guttenberg. You know, Alyeska has been there for a long time. There is a history of taking care of problems. You know, there haven't been any major spills. Spills at Pump Station 9 were contained within the bladder, but there were problems with how that happened as well.

People are concerned, but, you know, we are an oil State at the end of the day, and we look upon that as our flow of revenue, and people are at times really concerned about what would happen if there was a problem. So we are all over the place as far as how we review Alyeska.

Mr. Oberstar. I think what this hearing shows us all is vigilance, consistency, a high standard of safety management by the company, a high level of oversight by the Pipeline Safety Management Agency, both Federal and State in a cooperative relationship, particularly in a hazardous environment, all of which were absent in the Gulf.

It is just intolerable that the Minerals Management Service, under the previous administration, exempted BP from filing a blowout failure response plan. None was prepared. None was developed. They are showing today, even today, this very day, that they are still experimenting with containment and protection because they didn't think of it and they weren't required to think of it ahead of time. They were exempted from thinking about how to contain a failure at the wellhead and in the water column.

That failure jeopardizes 50 percent of the fish and shellfish resources of the United States, 300,000 jobs and the future livelihoods of millions of people in the Gulf area, and it stretches all the way up to the Chesapeake Bay where oystermen were counting on oysters from the Gulf off Louisiana to serve their customers here.

I was up on Eagles Nest Lake last week, just after the 4th of July, just on the edge of the boundary waters of the Cuyuna area, with my son and granddaughters, listening to the call of the loons. In 4 months, those loons are going to be migrating to the Gulf, and they are going to meet with a terrible fate if that oil isn't cleaned up, and it won't be cleaned up by that time because that is where they winter. They will be flying right into those marshes where the oil is gathered, and they are going to be Minnesota casualties, Minnesota loon casualties. If those loons don't return next spring, then BP is going to be to blame.

I will leave it at that.

Mr. Walz. Well, thank you to the Chairman for that summation.

I want to thank each of you on behalf of myself and the Committee for being here, helping us to understand this, helping to be partners in getting this right, as we said, to move a precious resource to fuel our country as well as doing it in a safe manner. It is invaluable.

To Mr. Jones and Mr. Guttenberg, thank you. I don't want to make light of the long travel you made. It truly was.

The hearing will be open for 14 days for Members who wish to make additional statements or to ask further questions. Unless there is further business today, this Subcommittee is adjourned.

[Whereupon, at 12:55 p.m., the Subcommittee was adjourned.]

[GRAPHIC(S) NOT AVAILABLE IN TIFF FORMAT]

EXHIBIT BMC-60

Line 5 Straits Alternatives Evaluation: Kick-Off Agenda January 17, 2018

| Primary Meeting Location | |
|--|---|
| January 17, 2018 7:00am to 2:00pm | |
| 200, Fifth Avenue Place 425 - 1st Street S.W. Calgary, Alberta | ➤ Reception and check in is on the second floor |

| | | |
|------------------------|----------------|---|
| Kick-Off Coordinators: | Amber Pastoor | Call us if anything comes up; you have a question; you get lost; etc. |
| | Jeff Kler | |
| | Brian McFadyen | |

IMPERATIVE LOGISTICAL NOTES:

- Please arrive on time we will start promptly at 7:00 am

Tuesday, January 16:

- For those of you arriving on the 16th please let Jeff, Brian or Amber know because we would be pleased to meet you for a group dinner

Wednesday, January 17:

- For those of you who will still be in Cow Town the night of the 17th we would be pleased to meet you for a group dinner

Schedule

Wednesday, January 17, 2018

| | | |
|-------------------|---|---|
| 6:45 am | <p>MEET AT ENBRIDGE RECEPTION - SECOND FLOOR LOGISTICAL NOTE: Breakfast will be provided</p> | |
| 7:00 am - 7:20 am | <p>Amber Pastoor, Enbridge Project Development <i>Life Changing Safety Moment & Introductions</i></p> | |
| 7:20 am - 8:20 am | <p>Amber Pastoor, Enbridge Project Development - Non-Technical Lead <i>Ground Rules - How We'll Work Together Roles and accountabilities</i></p> | <p>Dan C. - "We don't want Enbridge to have any surprises either" if they come ask with questions we weren't expecting. Hopefully we will be free to ask questions along the way. AP: Yes, ask questions. Success will be us presenting options for feasibility study.</p> |
| 7:20 am - 8:20 am | <p>Jeff Kler, Enbridge Project Development - Tunneling Lead <i>Feasibility vs Design</i></p> | <p>*Brian/Kyle delivered this section* KM: Seasonality is an issue in getting data right now. We need to remember to explain our assumptions we make. Adam: Presenting our options. Do we need to narrow these at all before June, or is the state happy if we don't make any recommendations or need specs at all? - will need to be discussed, but not decided upon. AP: We do not need to land on a recommendation, just evaluation. Mike M "Agreed" Mike M: "Talk about the risk assessment piece... it's critical to this. Listening to the folks at Michigan, the risk piece in the report that was done prior... Risk assessment should be a critical piece of this..." Identifying and</p> |

assigning risks

Dan C: "Want to understand the risk, interested in technical parts of it. What's interesting about risk is that public reception of risk is limited. People don't want to hear that it's made up of probability and consequence"

KM: we will do a formal risk session for each option, assign dollar value, contingency and escalation.

Trying to get as close to an UC as possible, but may not be feasible at this point.

Gary: "As far as I'm concerned, the 30% is done" ENB has invested in pre-feasibility, could probably use that as the pre-feasibility. (ENB engaged hatch following dynamic risk report - will review in tunneling section). Further advanced on the tunneling part than HDD/conventional lay.

AP: Will circle back with land to ensure that we can go do a site visit.

Adam: You can do preliminary design based off of google earth, but it is preferable to be on site and see the site.

TH: haven't been there lately. Question the value in having 20 people out to do a 20 minute look at site.

Jeff HDD: Hadn't talked about a site visit, it's not critical for feasibility as opposed to design.

AP: No site visit needed?

TH: If needed, could do it, but within reason.

Mike M: "have not seen the area, would be nice to see the area. Doesn't have to be tied to this. Do understand the winter nature, how much do you really see... It's hard to know"

TH: If there's value, go ahead and do it.

KM: The plan was to review the site early, if not right away. The "30%" dates are the only opportunity to get everyone out on site.

Brian: Could be a way to get local buy in.

AP: Not part of the feasibility review.

Gary: Value in hiring local geotech firm who has experience in the area. How are we handling all the onshore

modifications we have to make to the piping? Who is doing onshore facilities?

KM: Will probably be done in house.

Dan C: "Generally familiar with the area, both sides of the straights, but mac specifically. It is important to talk about surface impacts."

KM: South shore has restrictions (lighthouse, etc) that are tricky and has quite an elevation change.

Table the south shore discussion. Don't book travel to do 30% Kyle will confirm dates and get back to people by the end of the week.

Mike M: needs a slight shift in dates for the 30%.

KM: We won't have alignment opportunity for feasibility review.

KM: Hotel meeting room,

Mike M "Doesn't have to be in Denver. If it's going to be in one day, I can travel. Denver is a good location, hotel right at the airport"

Gary: Risk at 60% or final review?

KM: Both. We've identified a risk person, Stacey Denee, will review risk register as a team.

Adam: Do you have three cold eye groups?

KM: We are going to get cold eyes for each of the alternatives.

Adam: Are our reports going to be appendices to your final report.

AP: We don't have that decided yet. That would feel right, but unsure at this point.

KM: Technical writer will be on boarded ASAP so reports can align properly.

Jim M: Do you see the risk portion to be by Enbridge writer?

AP: Once writer is on boarded, will decided.

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| <p>Brian McFadyen, Enbridge Project Development - HDD Lead <i>How the Process Will Work - constructability review, cold eyes review</i></p> | |
| <p>Kyle Miller, Enbridge Project Development - PD Lead Field Studies = What's Possible</p> | <p>KM: Will not be doing core samples for the purpose of the feasibility study. The challenge is to get the right boat/vehicle to do sampling. Will be doing seismic reflectivity. Coast guard recommended against conducting a survey when it's iced over.</p> <p>TH: If you get enough ice you can drive out onto it.</p> <p>Gary: Should this phase include development of a geotechnical plan? KM: No. Gary: But assuming job will go forward, will need to do detailed design. Should we price it out? KM: Should be included in the price. We've gotten some preliminary pricing.</p> <p>AP: Key takeaway is "No drilling in the straights to support feasibility study"</p> <p>KM: Potentially take some samples on our existing ROW.</p> <p>Jeff Stantec: North side has some protected plants, would need to mitigate damage.</p> <p>AP: DO you think we could get permits for geotech etc in time for feasibility. Jeff Stantec: Wouldn't be able to say the timing, would be tough. AP: If it's needed by anyone in the room, let us know ASAP</p> <p>Mike M "States position is GO on geotech if you can, and that they would do whatever they can to accelerate [permits]."</p> <p>TH/Jeff Stantec: We need to find a person and a footprint. Paul: Need to arrange land access as well.</p> <p>Paul: If state agencies are able to make it a priority, unsure of timing. An application can be turned around to</p> |

be filed in days. An unmotivated permit application could take 3-4 months.

AP: We know whether the land is public or private, just not on the tip of tongue. Private landowner on south side (maybe?) probably county land on the north.

KM: We have two separate easements for the two 20" lines. Operations have anything open?

TH: This would be a good reason for a site visit. Take prelim alignment and see if there are spots to do onshore core drillings that are accessible and would align with environmental restrictions to put permits together.

Jim M: Would the consultants need to come up with geotech plan/investigation.

Gary: Onshore would be set when alignment is picked, phase two would be in the water.

Jeff P: There's value in getting deep borings. If we get deep borings on the ends, we'd at least have compositions and clay depths, etc. Material properties are what you would gain from the edge, but the middle bit is the critical place to get borings. There will probably be a lot of assumptions involved with our timeline, but borings would help solidify.

AP: Let us know what you need so we have time to get it.

KM: Doing bores on either side valuable?

Adam: It'll have some value to do.

Gary: Pulled public files for historical bores and locations.

KM: Plan is for Ballard Marine report to be found by ENB, do onshore borings, and then complete geotech plan at a later date.

Jim M: HDD gets by with very little data usually. Whatever is sufficient for JD Hare will be more than enough for us.

Adam: So we will need to decide what we need.

Mike M: Get the permit ASAP. "IS there a possibility that there exists additional data in the straights, not publically available, that a local geotech would know about?" "When you say geotech, do you mean seismic or borings?"

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| | | <p>KM: "Probably not borings"</p> <p>TH: MN state keeps a pretty good handle on any coring done across the state. Is there any state agency in Michigan that has record of geotech investigations?</p> <p>KM: We've been mainly working with SCM on this, maybe we can try contacting state.</p> <p>Mike M: "State government is maybe not the most reliable records... I will ask if they have records" "My understanding from the state is that [the bridge construction samples] are all that exists"</p> <p>TH: Might be worth checking if state has a record of minerals down there.</p> <p>AP: Most immediately, we will need to know... doing anything in the water is OUT... What the needs are from tunneling, HDD, and conventional lay. Paul needs a footprint, Rich has lands figure out, and Mike can grease the wheels of the state.</p> <p>Adam: We will take action to define what we need.</p> <p>Gary: Who will take the lead on the geotech program?</p> <p>TH: Don't worry about onshore right now.</p> <p>KM: You send us what you will need, and Enbridge will manage geotech.</p> <p>Gary: HDD and Tunneling consultants will need to put together the geotechnical scope.</p> <p>Adam: Can have prelim scope by early next week. Will confirm what's needed offshore to confirm feasibility study.</p> |
| <p>8:20 am - 9:10 am</p> | <p>Paul Turner, Enbridge - Environment Lead <i>Scope for Environmental Review of the Three Alternatives Needs List</i></p> | <p>Doing Environmental Impact Report as opposed to EA or EIS, because the latter have regulatory pull. When this is released to public, we will try follow all required criteria, but this will not be a formally regulated report.</p> <p>Cumulative impact would not be included in report as would be in NEPA report (not looking at upstream/downstream).</p> <p>KM: Wherever we land, we will have some impacts getting back to existing PS.</p> |

Paul: If there's changes to PS, trps, etc... We will cover that.
Dan Cooper returns from previous call

TH: How much of this actually has to be done, how much can be listed as items that will have to be done eventually.

Paul: All of the info in the EIR is a desktop study. Once we receive footprint, that's what we will use. Might use a bit of buffer though.

Jeff: The analysis will be on quite a bit of desktop data.

Jim M: Include disposal of cuttings and drilling fluid for HDD?

Jeff: At least a description of what will be done, if exact footprint etc is not known.

TH: Identifiers will be for drilling, we will have X cubic yards to be disposed of, for tunneling X cubic yards to dispose of, etc.

Paul: Will be including operations and maintenance impact as well. Will need time to complete report while ENB is completing theirs.

Gary: Who's going to generate all the layout drawings for EIR (plot plan, etc).

Paul: Will get a detailed request out to consultants next week to distribute to team.

KM: Each consultant will have their own plan, will be totally separate, and will need to provide to Stantec.

Paul: Data needs are outlined on the slide deck, pulled up. Do not change your design or report based on what I need at this point.

Jeff: Data needs will be put in a matrix and sent out early next week. For now, we will use what we think we will need for footprint, and add buffer.

AP: We need to challenge ourselves to remember that this is feasibility, not design.

Paul: The purpose of this will be to show that we have evaluated things.. Even if it's not an optimal location, we need to show we considered it and have decided against it. There are certainly risks to doing this and making it available publically. However, this is the agreement that was signed.

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| | | <p>TH: Just because we do the work to assess the feasibility, doesn't mean that every single little detail needs to be in the report. Unsure that we would have to include the exact layout/location of the solution in the public report.</p> <p>Gary: Should we make the effort on the south shore, to mitigate slightly with the feasibility study design? Surely the call can be made.</p> <p>Paul: State park is a showstopper... No recent permits have been released.</p> <p>Dan Cooper: "I'm assuming that if a tunnel were built to relocate the pipeline, ENB would go through the process to get a"... permit... While state has no jurisdiction for safety, they have citing authority under X16, gives the right of imminent domain to the company that receives that certificate.</p> <p>Adam: It comes down to whether this is iterative or not.</p> <p>Mike M: "This seems comfortable from a tunneling perspective" (referring to environmental report scope).</p> <p>AP: Make sure Stantec lets us know if there's any 'tidbits' they can use to get an early start. Ask of Dan and Mike to review Stantec's EIR plan and let us know sooner rather than later if there are any issues identified.</p> <p>Jeff: Please note that this report is just modelled after the Michigan state reporting... We don't want this tied to any definition of a regulatory review.</p> |
| <p>9:10 am - 9:30 am</p> | <p>BIO BREAK</p> | <p>Erica: Ask of AP to keep her in the loop on onshore options as well. Will probably 'piggyback' off of environment data.</p> |
| <p>9:30 am - 11:30 am</p> | <p>Tunneling Alternative <i>Table of Contents</i> <i>Sequence of Events</i> <i>Needs List</i></p> | <p>Gary: UC report draft has been provided to Steven Diep, comments received, Hatch will submit final report by end of the month.</p> <p>Mike M: "Do you know who did the tunneling aspect" Gary: Stantec</p> <p>Gary: Confirmed the dynamic risk option was feasible. Discrepancy found in costs - Hatch found the cost would be double what dynamic risk found.</p> <p>Jim M: Dynamic Risk report was completed?</p> |

Gary: October 2017. Fairly recent.

Grey: Assumed center was bedrock? Yes. Also pre-grouted middle in estimate.

Gary: Looked into potential for more efficient tunneling option than Dynamic Risk report. Looked at an option similar to an HDD, but with a bigger diameter, as well as an option where there is a shaft on the south end with boring coming in from the north side. Another option is to not go so deep and deal with the clay soils once we know what the compositions are, as it is possible to tunnel through soft material. Opportunities for Michigan to use this as a utility corridor as well. Micro tunneling was noted, but not developed, as it hasn't really been done for this depth/length. High level schedule was created for the boring option (with no shafts), 5 years from start of site prep to demob, with mining being ~2 years with two boring machines.

KM: Size wise, we would look at 12-15 feet, concrete segmented line, assume some grouting ahead of areas. Debate is whether or not we should grout the tunnel in when we are complete or not?

Gary: Some level of discussion should be had with people to discover economic opportunities to have this as a utility corridor.

Jim M: Would be unlikely to change the diameter at all.

Gary: Big wins with the tunnel, with boring machines you save money as opposed to shafts, another opportunity for cost to be significantly reduced by confirming clay soils compositions.

KM: Some of the issues, relating to gateway for cost, were operation of the tunnel, venting etc.

Brian: Tunnels were elaborate in NGP design, have been looked at by NGP group in Enbridge.

Gary: Challenge is getting the information to try to reduce the risk, and more opportunity to reduce the cost.

KM: Overall feasibility of the tunnel is what we're looking at, it looks like it can be done.

Adam: Reading DynRisk report excerpts, it seems like there was a lot of emphasis on benefits. We need to look at picking one of them, but then do a proper layout and try to find entrance/exit sites, etc, revise construction costs and estimates (without taking this to FEED). Any input we can get on what's most important will help guide decisions for Hatch feasibility report.

KM: Tunnel boring machine and specs are critical. Diameter is dependent on machines that are available.

Adam: Can make a bespoke machine from scratch in not too long. If we backfill, might not need to do a concrete segmented line (cost savings).

Adam: We should make a recommendation for one of the tunneling scopes.

Mike M: "I think it's a reasonable approach [to choose one]". A more contemporary boring machine option is a hybrid machine... Are you going to look into those options?

Gary: Yes - we didn't look into that yet at this phase, not quite at the point up until now to optimize the designs.

Adam: Couple million more for a hybrid machine, but de-risks significantly.

Mike M: "In terms on alignments, less concerned about one shaft/two shaft... [More concerned about the bore and de-risking]"

Gary: Is it feasible to see if we can get a rig out on the ice in the next few months and drill one hole to get that middle composition.

KM: Right now where we need that information is where the coast guard keeps it open, not frozen.

Adam/KM: Hybrid machine sounds worth it for a couple million more.

Mike M: "Another question is why two boring machines? Is that to drive schedule?"

Gary: Yes.

Mike: "In your feasibility, have you assumed a design line of the tunnel?" "On this notion with backfill, Michigan is very interested in a non-backfill option"

Dan: "Pipeline integrity mgmt., how can you inspect an inline tunnel in grout?"

Mike "A tunnel, not backfilled, provides advantage over HDD. Don't take that advantage off table in feasibility study"

Dan "Would going through soft material affect long term integrity of the tunnel? Because that is basically the secondary containment"

Adam: They're not intended to be completely airtight so to speak, joints are grouted, but there is the secondary tunnel.

Mike “In a segmental liner, the joints are gasketed, the pressures there are within range. [Not airtight, will need to look at some type of liner]”

Adam: With grout, it is a long way for any product to find its way through the grout.

KM: Could look at running FOC along line for additional LD.

AP: Can you use a rover or drone type thing through tunnel. Can it be made so that people can go in if necessary?

Adam: Can bulk head either end. Making it inaccessible at either end, but can make it accessible.

Gary: Lots of deep sewer examples where people access that aren’t ventilated etc, but can be accessed with proper PPE.

Gary: Can list all these as options.

AP: From an environmental impact, permanent shafts will be significant.

Paul: It’s still minor... No different than building a PS. Not a showstopper.

KM: I don’t think you need a shaft,

Mike: “If you can design a tunnel without a shaft, it’s not going to help you with operation of your pipeline.”

Gary: Site visit becomes very important at this point.

Jim M: Getting the pipe into the tunnel is an issue too... shafts complicate that.

Aaron: Not going to do a riser for 300ft

Gary: Are we concluding that we will not pursue shafts on both ends? While still including what we have so far on it in report.

Mike M: “What about design life” “Typically 100 years”

TH: Is the original south shore 30-40 acre parcel large enough/far enough back from water to get to depth?

Gary: Parks are no-go?

TH: Not first choice, but pick the most viable, most feasible site... park probably isn't it.

Gary: on the south side, the fallback is the shaft.

KM: Need to avoid the lighthouse though

Gary: Shaft might be flexible around lighthouse. Might be able to avoid double shaft.

KM: We can send Hatch the data on the north shore parcels, we already pulled all that. Request to stay off google earth, since that's public domain. Enbridge has its own, so Hatch should request to use that.

KM: Using the tunnel for other utilities is not for the feasibility study.

TH: The main issue is how to get this oil line across the straight and avoid failure.

Dan: "On the other hand, from a public communication standpoint, depending how you want public to perceive it, if you mention possibly including other utilities in the bottom of the straights, it would be a plus for a tunnel to include other utilities in the future."

TH: We should mention an opportunity to benefit the residents of the state of Michigan.

Adam: Feasibility study, we will size tunnel based on single 30" line.

Mike M: Great lakes twin study, can you describe more Kyle?

KM: Decided no go due to cost. Might be able to collaborate with trans Canada.

Mike M: "Did they do geotech?"

KM: We are looking into that. Mike, as the state, could reach out...

Mike "I'd be happy to reach out"

AP: Action item: Hatch to look at pros and cons (soon - approx. within 10 days) all options and we can decide to narrow down scope just a bit, as it impacts environmental study.

TH: to some level, we should evaluate all options for tunnel. Do Due Diligence and not take anything off the table.

Jim M: Can we get an understanding of what Hatch's scope will be?

Gary: We should all probably work together to make sure we cover everything and don't miss something.

Gary: New scope for us, is trying to figure out where we would put boring machines, waste requirements for

environmental report, possibilities of raising the base up.

Adam: Need to remember that this is not a tunnel project, it is a pipeline project. Need to consider pipeline stresses, etc.

Mike M: "There is still significant geotech risk. How will you address in the feasibility study, [aspects of tunneling risks... (ground water, etc)] to what extent will you do that in feasibility study?"

Adam: We do have some geotech, and it will be a 'thumbsuck'... Do what we can with what we have, and try to de-risk it as much as possible.

KM: Do we have data on the limestone/dolomite/clay material.

Adam: Not exactly to the depth we are at, but we can make assumptions based on the data we have. We're not trying to do a FEED level design yet, just feasibility, with mitigation strategies. Example, a big risk is schedule, but that doesn't impact the physical feasibility of tunneling.

Work will be done mostly in Vancouver, also Mississauga and Edmonton.

Mike M: "Will Gary be involved"

Adam: Our expert tunnel reviewer will be involved, he's located in Mississauga.

AP: Will we ask Hatch to go away over the next ~10 days, put together a pro/con list, have thoughtful debate, and select one tunnel option (or at least remove one option) so we don't put effort into something that we think won't be as feasible.

KM/Adam: Yes. Can provide a memo even, and Enbridge can provide a decision record.

Gary: Does the ranking need to be a formal SME discussion with presentation to Enbridge with a session?

KM: It is my wish that we do that at the 30% review. Yes, that is the way it should be done.

Dan C: "The report with the agreement for the state, is a report that looks at 3 options (HDD, Tunnel, burial), this is only one part of the report"

AP: Dan and Mike, you're on board with the idea of having one main feasibility study option per HDD, tunnel and burial?

Dan C: "Definitely. Was just looking at this from the perspective that issue to be comparing lead cases for each

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| | <p>option?” AP: Yes</p> <p>Mike: “Yes”</p> <p>KM: Will be following our standard WBS for this project.</p> <p>TH: Would like to see some general evaluation of geometry of type of tunnel, and timeline of the next couple of months of what needs to happen to meet our deadline. We need to think longer ahead than 10 days.</p> <p>Paul: Maybe we should just look at a large area on either side of the straights and list potential restrictions and issues. Instead of identifying specific impacts, and just list all potential impacts to be inclusive of all options. Show the different features identified from desktop review.</p> <p>Mike M: “Most certainly [state wants to see a comparative analysis]” Jeff: Saying that one option might have more impact than another option, without getting into specifics.</p> <p>Paul: Not going to make a conclusion for which is the best environmentally. Just need to list the impacts.</p> <p>Jeff: May not need specific GIS files, but we do need general ones.</p> <p>Jeff to Mike: Will the state come back when we’re done the report and say, this isn’t what we wanted, we wanted specifics? Mike M: “We hope to avoid that by along the way keeping them updated of what the report will entail”</p> <p>KM: We want all the reports structured exactly the same.</p> <p>Gary: HDD and tunneling will each have a schedule... Do we have any direction on formatting? KM: We’ll have a scheduler. We will do a high level schedule.</p> <p>Mike M: “Risk discussion so far, ex tunnel risk mgmt. and register, has been about identifying and reducing risks Michigan is interested in long term risk of leakage into the straights. Is there going to be some analysis on quantifying risk of leakage into the straights”</p> <p>Action: Enbridge to figure out how to quantify probability of product hitting the straights.</p> <p>TH: We need to address that, in this study of the three options. Ex how big a risk is it that a leak will hit the water before we detect it.</p> |
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KM: We could do a HAZOP, would have more value than a value engineering session.

Dan C: "Not sure a HAZOP will give the state what it wants" It will identify concerns, but the state wants to hear "the HDD has a one in a million risk, tunneling has a one in 500000, "DynRisk talked about risk in terms of dollar value... Avoid that, and talk about risk in probability. State doesn't care about the dollar value associated with risks" "Can include the cost in the decision, but don't state it in terms of money"

KM: This will be a different risk session

Dan C: This is more of a probability... Any of the options could leak into the straights, but need to evaluate volumes and probability that product will get into the lake.

KM: Probably less for tunnel and HDD.

Dan C: Probability? Because you're down deeper?

AP: Yes.

Dan C: Not just the probability of a pipeline failure, probability of the product reaching the water.

Adam: That should probably be considered in the Enbridge portion of the report.

Aaron: Geotech available for nuclear waste project off Lake Huron. Probability could be difficult without having geotech confirmed.

AP: Will have to take leak modelling idea.

KM: Leak modelling once product hits water is in DynRisk report

AP: Probability of leak and oil hitting the straights Dan and Mike?

Dan C: What are threats to pipe itself causing leak, and if it does happen, what is the probability of the product hitting the water.

KM: DynRisk report also included seismic activity.

Mike M: "I'd want [seismic analysis] done. If there's earthquakes, public doesn't understand earthquake probability,

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| | | <p>Dan C: "That info is available on US GIS"</p> <p>Mike M: "Tunnels are designed for seismic loading"</p> <p>Hatch Deliverables: Position paper, onshore geotech requirements. KM: has to be on our easement. Easiest approach is on our existing land.</p> |
| 11:30 | <p>WORKING LUNCH</p> <p>LOGISTICAL NOTE Lunch will be provided</p> | |
| 11:45 am - 1:35 pm | <p>HDD Alternative Table of Contents Sequence of Events Needs List</p> | <p>Might not be feasible to do a 4 mile HDD. Pullback has never been the limiting factor. Longest HDD Jeff is aware of is ~1200 ft.</p> <p>First option is the full length pull, not very feasible due to length and diameter required.</p> <p>Jeff: What are the other options? How can drilling be used? Second option is two intersects - finishing a spot out in the middle to put a rig to drill to the middle. This is still close to the record, and has some risk - it is possible. In order to do that, would need a jack up vessel and support vessels tethered to it. This rig needs to be fairly stable. The concern would be the water depth, as well as handling drill string, as well as containing drilling fluid, would run a conductor casing, which would allow the mud to flow back up onto a hopper or mud barge. Some contractors will try to limit the amount of mud coming out of the water. KM: This option would put us right in the middle of a shipping lane.</p> <p>Third option is 3+ intersects, with multiple platforms in the water where the water was shallowest.</p> <p>Fourth option is to do HDD at the shoreline, with some conventional lay in the middle.</p> <p>Typically, crossing limestone would be feasible. If we can get some borings on land, it would be helpful, but not critical.</p> <p>The risk in HDD when you get into karst is that you have a cavern, and they've drilled into essentially nothing, getting back into the rock on the other side. It is avoided to the extent possible. HDD is not used in known karst areas.</p> |

Could be going into and out of bedrock quite often. For marine drills, the materials are not always ideal.

Ideal would be to get into rock, stay deep, and stay in rock. Coming out of bedrock into soft material is fine, but going back into hard material it is hard to maintain alignment. This is not so much a feasibility issue, more a risk than anything.

What is the water depth limit for a jackup? Unknown off top of head. (Brian: for offshore wind, 50m is about as deep as you want to be).

AP: Lets document with thoughtful analysis before immediately pulling something off the table right away.

KM: Let's have something by the end of next week to lay out the options.

Jim M: Will have to list the limiting factors.

Jeff: We will look into issues and concerns. Not saying it's impossible to do, it depends on Enbridge's tolerance for being the first to attempt.

TH: If you have two intersects out there, you'll have two segments of shell pipe.

Jeff: Also, mud will float to the surface, no matter what mitigation is done. For this depth, it might not be as big of an issue.

Mike M: "A lot of things in the negative column for HDD, the state kinda knows this going in, that this would be a record. Don't want to say too much, not making the decisions, this is the 'long shot home run' of the three"

Jeff: Seeing a tunnel option end to end, the odds are stacked against HDD. HDD would come in at a lower price than tunneling, but does it do what is needed?

AP: Over the next ten days or so, lay out the options for HDD, advantages and disadvantages of those options, we'll put it into a formal memo, it'll become part of the HDD report, and then we will try to help narrow down the scope to focus feasibility on. Findings would be presented to the group at 30% feasibility review meeting. What ENB will provide to you is a table of content for the report (not the initial memo) to show what needs to be in it.

Jeff: It's worth looking into. Doubling state of the art is probably not the approach. Challenges are the rig and the drill steel, and pile hold. Many historical marine HDDs have been more ideal conditions and material, softer

materials.

Pile holds would be about 12” ish.

Jim M: When you go to a bigger size, you get more torque out of it, but the pull force is the same. Did a quick calc on pull for a 2MM lbs... Very risky.

Jeff: When one end of pipe is in water, you can float it or fabricate in the water, or the easier thing is to lay it out on land, but that requires a large workspace on water and land.

Mike M: “When you go from 12” to final size, is it a single ream?”

Jeff: Would be in 2 or 3 steps.

Mike: “What about if you go through ship channel, are they concerned about keeping it open, or are pressures sufficient?”

Jeff: Concern is going from soft material into hard. Would generally try to run the surface casing down into bedrock. It is possible, depending on how soft the material is, to keep it open.

Mike: If you can’t go jack structure, you would case it across the clay?

Jeff: Generally, we would have a casing that ran from above surface of water through water column to sea floor. It may not be reachable at this depth.

Jim M: another factor is the amount of time you will be there, and hole erosion.

Jeff: don’t know if there’s much variation in water depth, but off east shore, the tidal influence was challenging for depths.

KM: Requested data from Michigan tech, they have a buoy. The currents are currently an unknown. Imagine it would be available to us.

Jeff: If we had actual current data, we’d have to look into how to quantify this.

Jeff: Main things we need to get started, are current pipeline alignments, and then the ideal alignment, and then some sort of geographic profile, we can look at some of the info from existing boring logs. Our needs are limited for the feasibility assessment. Assuming that we can find a spot on land to work on.

KM: We need to make sure we clarify and state assumptions. Need to try to de-risk as much as possible.

Jeff: Could potentially enter/exit at PS on south shore.

KM: If the risks start to become overwhelming, we would probably lean towards not pursuing any further.

Mike M: "You won't be able to quantify karstic features... What size of a karst feature causes a sufficient enough problem to stop an HDD?"

Jeff: Will have to get back to you, not off top of head. About a join of drill pipe, maximum.

Jim M: Might be even less than that, because of the extra weight on the front of it.

Jeff: 30ft is a reasonable limit, maybe a bit less than that.

Dan C: "Somebody will likely ask the question... What if you were to drill from both sides and meet in the middle" start from north and south each, and meet in middle.

Jeff: That is what we're envisioning, but the longest that has been done, is 12000-13000 feet total. A practical limit would be 7000ft each end.

Dan C: Was misunderstanding jackup rig... Would that be drilling from the platform?

Jeff: Yes, one direction.

Dan C: They're usually either drilling down and put casing in to keep it from collapsing. Still would have anchor concerns if it's jetted. Ideally, you would bore down below any possibility of anchor strike.

Aaron: If you do intersect, the tie in locations will be shallower or more vulnerable to anchor strikes.

Jeff: Can do a concrete pour for the sections that are near the surface, and tie ins.

Environmental: scouring, release of bentonite, drilling mud. Would be concerned about mud and bentonite release smothering sturgeon eggs during spawning season (risk, not a showstopper). Contamination expectation is a pretty clean sediment at the bottom.

Could you set up to do drilling out on the ice. It would be a risk to have a thick enough ice. It's a possibility, but would be risky if the ice was around long enough. Rigs and fluid generate a lot of heat, so would have to insulate from the surface of the ice. Could possibly build the ice up artificially.

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| 1:35 pm - 1:45 pm | BIO BREAK | |
| 1:45 pm - 2:00 pm | Entire Group Questions, Observations | <p>Date for 30% design review is to be taken away. It will be the week of February 5th. Could hold tunneling earlier if desirable. Will decide by the end of the week.</p> <p>Both groups to come prepared with their memo on forward steps for feasibility. Enbridge to provide table of contents. Technical writer to be brought in ASAP. Local geotech would be desirable sooner rather than later. Consultants to get requirements to Paul soon so he can get permits sorted out.</p> <p>Lines of communication: to contact the Enbridge PD leads.</p> <p>Dan will take point on conventional lay - to be looped into Jan 18 meeting if possible.</p> <p>Environment will send formal data as by Tuesday next week.</p> |
| NEXT STEPS | | |

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of Enbridge
Energy, Limited Partnership for Authority to U-20763
Replace and Relocate the Segment of Line 5
Crossing the Straits of Mackinac into a Tunnel ALJ Christopher Saunders
Beneath the Straits of Mackinac, if Approval is
Required Pursuant to 1929 PA 16; MCL 483.1
et seq. and Rule 447 of the Michigan Public
Service Commission's Rules of Practice and
Procedure, R. 792.10447, or the Grant of other
Appropriate Relief

TESTIMONY OF BRIAN J. O'MARA
ON BEHALF OF
BAY MILLS INDIAN COMMUNITY

February 3, 2023

BRIAN J. O'MARA
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

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BRIAN J. O'MARA
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

1 **I. Introduction & Qualifications**

2 **Q. Please state your name and job title.**

3 A. My name is Brian J. O'Mara. I am the founder and Principal of Agate Harbor Advisors
4 LLC, a consulting firm that provides technical support in the assessment and
5 quantification of environmental risk and liabilities and develops evidence and experience-
6 based solutions for complex problems related to historic, existing, and proposed
7 industrial developments. I also provide environmental and technical due diligence
8 support for mergers, acquisitions and divestitures, and litigation support. As a Principal, I
9 serve as an independent client advisor and technical expert on environmental matters
10 including geology and hydrogeology; soil, rock and fluid mechanics; hydrocarbon fate
11 and transport; recovery, containment and remediation; and heavy civil construction (i.e.,
12 tunnels and shafts, landfills, impoundments and waste containment, treatment or disposal
13 facilities).

14
15 **Q. On whose behalf is this testimony being offered?**

16 A. I am testifying on behalf of Bay Mills Indian Community ("BMC"). This testimony
17 reflects my own independent opinions.

18
19 **Q. Please summarize your relevant work and educational background.**

20 A. I graduated with a B.S. in Geological Engineering from Michigan Technological
21 University in January 1987. I completed numerous post-graduate courses in civil and
22 environmental engineering and geology at the University of Wisconsin-Milwaukee and
23 Wayne State University. I completed numerous continuing education short courses for

BRIAN J. O'MARA
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1 professional development hours related to geology; hydrogeology; civil, geotechnical,
2 and environmental engineering; geotechnical instrumentation for tunnels and shafts;
3 grouting practice for tunnels and shafts; landfill design and construction; soil,
4 groundwater and hydrocarbon remediation, with organizations including USEPA,
5 MSHA, University of Waterloo and Northeastern University and the Michigan DEQ and
6 EGLE.

7
8 I completed specialty training in Mine Rescue and Tunnel Safety; Methane Management
9 in Tunnels; Hazardous Waste Operations and Emergency Response (HAZWOPER); and
10 Construction. I have served as Site Safety Officer for complex environmental remediation
11 projects that involved Level-B supplied air respirators for Superfund Sites in Michigan
12 and Vermont.

13
14 I maintain a membership in the American Institute of Professional Geologists (AIPG) and
15 the Association of Environmental and Engineering Geologists (AEG). I have previously
16 held memberships in the Society for Mining, Metallurgy and Exploration (SME), the
17 American Institute of Mining, Metallurgical and Petroleum Engineers (AIME) and the
18 National Groundwater Association (NGWA) – Scientists and Engineers Division.

19
20 I have worked on all phases of tunnels and shafts from concept, planning, design, and
21 permitting, to construction, operations, decommissioning, and closure. I have worked on
22 more than three dozen tunnels (up to 32-ft diameter) and numerous shafts (up to 120-foot
23 diameter) that total more than 50 miles in length and to depths of more than 300-feet. I

BRIAN J. O'MARA
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

1 completed 360-degree geologic mapping of more than 5 miles of rock tunnels. I
2 supervised the completion of more than one mile of pre-design geotechnical soil borings,
3 rock cores, and installed thousands of feet of piezometers and monitoring wells. I
4 directed numerous tunnel and shaft pressure grouting projects to improve ground
5 conditions and limit groundwater infiltration.

6
7 I have direct experience working in, monitoring, and mitigating toxic and hazardous
8 gasses (i.e., methane, sulfur dioxide, carbon dioxide, carbon monoxide, and low oxygen
9 levels) in tunnels and shafts.

10
11 I received advanced training from NIOSH regarding the detection, mitigation, ventilation,
12 and prevention of accidents related to hazardous gasses during tunneling and
13 underground mining. This course was developed in response to a fatal methane explosion
14 that killed three tunnel workers on the Milwaukee Deep Tunnel Project where I worked
15 as Resident Inspector and Staff Engineer.

16
17 My C.V. is attached as Exhibit BMC-61.

18
19 **Q. Have you testified before this Commission or as an expert in any other proceeding?**

20 **A.** I have not testified before this Commission in any other proceeding. I have testified as an
21 expert witness in the following case:

22

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1 *Bates v. GSC Principals and OH Env't Rev. Comm'n*, Docket No. L-07-1185 (Oh. Ct.
2 App. 2008) (appealed from *City of Oregon Ohio v. OEPA* as part of Appeal of Permit
3 Modification for Vertical Enlargement of Cell M RCRA-C Landfill).

4
5 **Q. What is the purpose of your testimony?**

6 A. I was asked by Bay Mills to opine on the ability of the proposed tunnel's concrete
7 structure to withstand a fire and/or a high-pressure event within the tunnel. I was further
8 asked by Bay Mills to provide an opinion on whether, in the event the concrete structure
9 of the proposed tunnel failed, Line 5 product would be able to overcome the hydrostatic
10 pressure outside of the tunnel and migrate into the surrounding geology and into the
11 waters of the Great Lakes.

12
13 **Q. What information did you review in preparing your testimony?**

14 A. I reviewed documents specific to this matter including: the Commission's Order dated
15 July 7, 2022; Mr. Godfrey's testimony and Probability of Failure Analysis submitted on
16 October 21, 2022, and the testimony of Mr. Dennis, Mr. Philipenko, and Mr. Bott
17 submitted on January 17 and 18, 2023; a transcript of the proceedings held on January 18,
18 2022, Volume 8 and January 20, 2022, Volume 10; various documents submitted by
19 Enbridge in support of their application, including Enbridge's Tunnel Design and
20 Construction Report produced as Exhibit A-13; Enbridge's Geotechnical Data Report
21 produced as Exhibit MM-4; and, McMillan Jacobs Technical Memoranda that was
22 submitted to the State of Michigan on May 24, 2021. I also reviewed various secondary
23 sources including peer-reviewed technical journal articles.

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Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit BMC-61 (BJO-1) CV of Brian J. O'Mara
- Exhibit BMC-62 (BJO-2) Enbridge's Response to Staff's Ninth Discovery Requests No. 9(12)
- Exhibit BMC-63 (BJO-3) O'Mara Calculations

II. The Proposed Concrete Tunnel Structure is Vulnerable to Damage Following a High-Pressure Explosion and Fire.

Q. Have you reviewed the Commission's Order dated July 7, 2022, issued in this matter and, specifically, page 45 of the Order which states: "However, there is no information on the record regarding the concrete's ability to withstand the effect of a high-pressure air impact from an explosion."

A. Yes, I reviewed the July 7 Order and, in particular, the Commission's observation on page 45.

Q. And did you review the discovery exchanged between Staff and Enbridge on this issue?

A. Yes. I was provided with Exhibit BMC-62.

Q. What is your understanding of the basic design of the tunnel?

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1 A. Based on the Tunnel Design and Construction Report that was produced in this
2 proceeding as Enbridge Exhibit A-13, my understanding is that the tunnel will have an
3 approximately 21-foot inside diameter, will be approximately four-miles long, and will
4 be lined with a precast tunnel lining (PCTL). The tunnel will be open and accessible to
5 allow for pipeline installation, pipeline maintenance, and inclusion of other third-party
6 utilities. The PCTL will be composed of six segments and incorporates high-strength
7 rubber gaskets to limit water leakage. The tunnel will be constructed in a V- or U-shape
8 design to keep the tunnel below the lakebed of the Straits.

9

10 **Q. Describe how an explosive event could occur in the proposed tunnel.**

11 A. Generally, an explosion will occur if flammable gas or vapors are present in the air of the
12 tunnel at a concentration that is between the Lower Explosive Limit (LEL) and the Upper
13 Explosive Limit (UEL), and those gasses or vapors are ignited. There are two sources of
14 flammable gasses or vapors that will be present in the tunnel project: the product
15 transported through Line 5, and groundwater with dissolved methane that may infiltrate
16 the tunnel.

17

18 **Q. Describe the way in which an explosive event could occur as a result of the release**
19 **of product from Line 5.**

20 A. The product transported through Line 5 includes light crude oil and natural gas liquids
21 (NGLs). Anything from a pinhole release to a full rupture of the pipeline that causes
22 product to spill and release vapors, which are generally heavier than air, that will then
23 settle in the lowest elevation of the tunnel. However, methane, discussed in more detail

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1 below, is lighter than air and as a result, will rise when released into the air and
2 accumulate in the roof or crown of the tunnel. Once the vapors accumulate above the
3 LEL and below the UEL, a spark or other ignition source could create an explosion.

4
5 **Q. Focusing now on Staff's observation that the Commission found that there is no**
6 **information on the record regarding the concrete's ability to withstand the effect of**
7 **a high-pressure air impact from an explosion, do you have an opinion as to how the**
8 **concrete would be impacted following an explosive event due to the release of Line 5**
9 **product within the tunnel?**

10 A. Yes. The concrete lining of the tunnel would be damaged severely by fire and/or an
11 explosion. A product fire can ignite a gas or vapor explosion and a gas or vapor explosion
12 can ignite a product fire. While a gas or vapor explosion can cause considerable damage
13 to a concrete tunnel liner and destroy a pipeline, ventilation systems and nearly
14 everything else in a tunnel, a fire ignited by an explosion or another source is more likely
15 to cause widespread failure of the tunnel liner and lead to a total collapse of the tunnel.

16
17 A release of product (and resulting gas or vapor) that is ignited by a spark or other
18 ignition source would result in a fuel-rich flame and intense heat. The heat of the
19 resulting fire could exceed 1200°C. It is well documented that temperatures of that
20 magnitude can cause the surface of the concrete tunnel lining to experience violent or
21 explosive spalling. Spalling occurs when pieces of concrete separate from the concrete
22 surface as a result of rising pore pressure and compression due to heating. The spalling
23 can continue to the point where the underlying embedded reinforcement steel is exposed.

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1 The fire will then heat the exposed reinforcing steel and can soften it to the point where it
2 can lose more than half its strength. As the temperature within the tunnel increases from a
3 fire, the steel will deform, ultimately causing buckling and failure. The weakening and
4 deformation of the steel support can then cause the affected overhead portions of the
5 tunnel segmented liner to fail and collapse due to the extreme weight of the rock,
6 sediment and water above. Similar failures occurred at the World Trade Center where
7 large quantities of jet fuel burned with intense heat that weakened structural steel causing
8 one or more floor sections to fail, triggering a chain reaction or “pancake failure.”

9
10 Incidents involving hydrocarbon fires burning in concrete tunnels, producing the
11 explosive spalling effect described above, are well-documented events and have been
12 examined in peer-reviewed technical journals. One of the most infamous examples is the
13 2001 Gotthard Road Tunnel Fire in Switzerland. Two trucks collided within the tunnel
14 and a short-circuit ignited the diesel-air mixture in the air. Temperatures of the resulting
15 fire exceeded 1200°C and caused explosive spalling of the concrete tunnel structure. A
16 300-meter stretch of the tunnel collapsed.

17
18 A 10-hour fire with temperatures that reached up to 700°C occurred in the Channel
19 Tunnel, a 31-mile-long transportation tunnel that runs beneath the English Channel
20 between England and France. The fire, which was initiated on a truck, destroyed parts of
21 the concrete tunnel rings by thermal spalling over the length of a few hundred meters,
22 leaving the chalky limestone overburden exposed. The stability of the chalk above the
23 tunnel kept the English Channel from rushing into the open tunnel crown. A similar liner

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1 failure in the Line 5 tunnel would result in a catastrophic in rushing of fractured rock and
2 sediment into the tunnel because of the poor quality of the bedrock.

3
4 In the United States, a fire in the Caldecott Tunnel near Oakland, California occurred
5 after a truck with approximately 8,700 gallons of gasoline was in an accident. The
6 resulting fuel-oil spill caught fire and burned for less than an hour. Within that time the
7 fire burned at a temperature of at least 980°C. The tunnel lining was damaged by the
8 intense heat; spalling occurred from the accident location all the way to the entrance
9 portal, approximately 1720 feet away. In addition, the tunnel wall tiles, water pipes,
10 lighting, communications, signage, and emergency panels were all extensively damaged.

11
12 There is a reason why, in Michigan, hazardous materials are banned from transportation
13 through the Detroit-Windsor tunnel. And there is a reason why there are so few oil and
14 gas pipelines installed in tunnels worldwide. Moving large quantities of hydrocarbons in
15 enclosed spaces, like tunnels, is dangerous.

16
17 The above examples highlight the destruction that can occur when a relatively small
18 volume of hydrocarbons is released from a vehicle and burned in a tunnel. But consider
19 not just a leak from a vehicle's fuel tank, but an entire hazardous liquids pipeline that
20 ruptures and releases tens of thousands of gallons and catches fire. A fire of that
21 magnitude in the proposed tunnel project creates the very real risk of spalling of the
22 concrete that may in turn weaken the tunnel structure to the extent that it fails.

23

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1 **Q. Has Enbridge identified sufficient fire suppression to address the risk of a fire**
2 **following an explosive event?**

3 A. No. Section 3.8 of Enbridge's Design and Construction Report details Enbridge's fire
4 response. Enbridge has no active fire suppression system for the Line 5 tunnel and relies
5 only on passive fire-resistant concrete and stopping ventilation. The state of the practice
6 for fire suppression in tunnels includes the use of Fixed Fire Fighting Systems (FFFS)
7 and advanced ventilation systems that can quickly extinguish or limit fires and facilitate
8 the removal of smoke so fire fighters can rescue trapped workers and extinguish fires.
9 FFFS have been retrofitted in tunnels like the Chunnel and FFFS have proved effective in
10 putting out fires in underwater tunnels in Tokyo, Sydney and Melbourne.

11

12 Enbridge states that, in the event of a fire, it will secure the air lock and switch-off the
13 ventilation system to starve the fire of oxygen. This plan ignores the fact that a fire in a
14 tunnel usually reaches its peak temperature within 5 minutes. Crucially, sealing the two
15 ends of the tunnel can lead to internal temperatures greater than if the tunnel portals were
16 not sealed. Enbridge's plan would likely exacerbate the already heat-intense fire.

17

18 Even if the tunnel was effectively sealed off, there would be more than 6,500,000 cubic
19 feet of air in the tunnel, which could provide enough oxygen for a fire to burn for well
20 over two hours. Enbridge stated it could lose up to 2 percent of the product shipped
21 (approximately 460,000 gallons) before they detected the release using their pressure and
22 flow monitoring approach. The amount of time before detection could result in a very

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1 large pool of product with a limited surface area that could burn for hours or days before
2 it was “starved of oxygen”.

3
4 During the entire time that the fire is being passively suppressed through closing off the
5 tunnel, the tunnel structure itself would be vulnerable to the intense heat of the fire and
6 subsequent spalling and collapse as I’ve described above.

7
8 **Q. How do you respond to Enbridge’s plans which state that “the risk of a fire within**
9 **the tunnel if the tunnel is unoccupied by maintenance personnel is negligible**
10 **because there would be no ignition source present as everything in the tunnel is**
11 **meeting requirements for Class I, Division 2?”**

12 A. Based on my professional experience, it is my opinion that Class I, Division 2 electrical
13 equipment is insufficient. Class I Division 1 electrical equipment is both feasible and
14 prudent based on the unique tunnel design and associated risks if there is a product
15 release from the pipeline.

16
17 **Q. You previously stated that methane will also be present within the tunnel. Please**
18 **describe the way in which an explosive event could occur due to the presence of**
19 **methane.**

20 A. Dissolved methane could be introduced into the tunnel anytime during the excavation of
21 saturated rock and sediment by the tunnel boring machine and indefinitely by the never-
22 ending seepage of groundwater into the tunnel through groundwater infiltration through
23 the joints of the precast concrete tunnel segmented lining as well as through leaks in the

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1 portal and exit shaft during the pipeline operation. Methane exposed to an ignition source
2 will ignite between a concentration of 5 to 15 percent methane in air. Only a small
3 amount of energy is required to ignite an explosive mixture of methane in the air. A
4 minimum energy requirement of 0.3mJ is needed with a methane concentration of 8.5
5 percent. The spark generated between a person's finger and doorknob after walking
6 across carpeting on a dry day produces significantly more energy than required to ignite a
7 methane/air explosion. There are various opportunities for a spark to occur within the
8 tunnel due to maintenance work and accidents, equipment operations or failures, static
9 electricity, sparks, flames, ground movement and freezing conditions. Furthermore, a
10 methane explosion could be triggered by the energy generated by a lightning strike to the
11 ground outside the tunnel. A lightning strike to the nearby ground can penetrate a tunnel
12 by various means, such as propagation through the overlying soil and rock; conduction
13 (or induction) in metallic structures, pipes, or cables extending from the ground surface to
14 near the tunnel; or induction through the earth onto underground conductors. Methane
15 explosions in tunnels and underground mines are well-documented.

16
17 **Q. Focusing again on Staff's observation that the Commission found that there is no**
18 **information on the record regarding the concrete's ability to withstand the effect of**
19 **a high-pressure air impact from an explosion, do you have an opinion as to how the**
20 **concrete would be impacted following an explosive event due to the presence of**
21 **methane in the tunnel?**

22 A. A methane explosion in a confined space like the tunnel project would be like a shotgun
23 blast—a blast through a barrel that quickly explodes and burns the methane in the air.

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1 This kind of high-pressure event can cause loss of human life, damage to the tunnel lining
2 and equipment, and cause a rupture of the pipeline itself—which in turn could then lead
3 to an explosion and fire described.

4
5 **Q. Are you concerned about a methane explosion occurring in the proposed tunnel?**

6 A. Yes, I am very concerned about a methane explosion occurring in the proposed tunnel.
7 My concern is informed by my direct experience working on the Milwaukee Deep
8 Tunnel Project—a project where three workers were killed following a methane
9 explosion.

10

11 My concern is also informed by the fact that Enbridge has made statements that methane
12 was not detected in the Straits, but that position is directly contradicted by its own
13 Geotechnical Data Report (GDR). Enbridge's GDR indicates that methane was found in
14 19% of the groundwater samples tested—and given the small number of samples tested
15 (less than one per 1000-feet of tunnel length), it is likely that more methane will be
16 encountered in areas that have not been tested. .

17

18 And finally, methane was identified as the cause of the explosion in the Lake Huron
19 Water Tunnel in 1971. The explosion was caused when a steel drill bit sparked and
20 ignited a pocket of methane accumulated in the tunnel. The resulting blast created a
21 shock wave that traveled with a speed of 4,000 miles per hour and a force of 15,000
22 pounds per square inch that tore through the tunnel, killing twenty-two men , destroying

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1 the metal ventilation piping, collapsing a part of the tunnel ceiling and throwing a 15-ton
2 piece of equipment more than 40 yards..

3 A methane explosion is a high-pressure event that has the risk of severely damaging the
4 proposed tunnel.

5

6 **III. The Conditions Outside the Tunnel Will Not Prevent Line 5 Product from**
7 **Migrating into the Straits Following a Release**

8

9 **Q. As you stated, you previously reviewed Mr. Kuprewicz's testimony provided in this**
10 **matter, correct?**

11 **A. Yes.**

12

13 **Q. Directing your attention to Volume 10 at page 1395, lines 6-22, do you see where**
14 **counsel for the MPSC Staff asked Mr. Kuprewicz the following question: "[F]or**
15 **Line 5 product to escape the tunnel and reach the Straits of Mackinac following an**
16 **explosion or a fire, the product would need to overcome the hydrostatic pressure**
17 **outside of the tunnel and migrate into the geology surrounding the tunnel?**

18 **A. Yes.**

19

20 **Q. And Mr. Kuprewicz testified in response that he did not opine on the hydraulic**
21 **issues that were in the testimony and that he is not a geologist, correct?**

22 **A. Yes.**

23

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1 **Q. Are you a geologist and, if so, what kind of experience do you have with tunneling**
2 **and hydrocarbon releases?**

3 A. Yes, I am a geologist and I have extensive experience with tunneling and, more
4 specifically, I have experience with tunneling in the Great Lakes with geology similar to
5 the proposed Line 5 tunnel. I also have three decades of experience with the investigation
6 and remediation of hydrocarbon releases at contaminated sites across the US and
7 globally. My experience is detailed on my CV, which is Exhibit BMC-61.

8
9 **Q. Based on your experience as a geologist who has worked on many tunnel and**
10 **hydrocarbon release projects, do you have an opinion as to whether Line 5 product**
11 **could escape the tunnel and reach the waters of the Straits in the event of an**
12 **explosion or fire inside the tunnel?**

13 A. Yes, in my opinion, an explosive event or fire within the tunnel could result in a localized
14 collapse of the tunnel lining or secondary containment, as described above, and Line 5
15 product would then escape the confines of the tunnel and migrate into the surrounding
16 rock and sediment and ultimately would reach the water of the Straits of Mackinac.

17
18 **Q. What does it mean to “overcome the hydrostatic pressure outside of the tunnel?”**

19 A. Hydrostatic pressure is the downward force exerted by gravity from the water, sediment
20 and rock present above the proposed tunnel. The pressure is different at varying points in
21 the proposed tunnel elevation. For example, the hydrostatic pressure is going to be the
22 highest at the lowest depth of the tunnel compared with the pressure that would be
23 present at either end of the tunnel. McMillan Jacobs Associates has estimated in its

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1 Technical Memorandum dated May 24, 2021 that the hydrostatic pressure at the deepest
2 part of the tunnel to be 17 bar, which is roughly equivalent to 250 psi. To overcome the
3 hydrostatic pressure at the deepest part of the tunnel, the product would need to be
4 released at a pressure that exceeds 250 psi.

5

6 **Q. Do you have an opinion as to whether, in the event of an explosion or fire within the**
7 **proposed tunnel, Line 5 product could overcome the hydrostatic pressure outside of**
8 **the tunnel following a release?**

9 A. Yes, in my opinion, if a fire damaged the tunnel to the extent that the secondary
10 containment system was breached, Line 5 product would overcome the hydrostatic
11 pressure outside of the tunnel and migrate upwards into the waters of the Straits.

12

13 **Q. Please explain.**

14 A. The pipeline maximum operating pressure is 1440 psi, more than five times the
15 maximum hydrostatic pressure (about 250 psi) at the deepest part of the tunnel. If the
16 pipeline wall is breached, the product will be discharged at the operating pressure, about
17 1440 psi. If the pipe is severed entirely, the product would continue to flow at nearly
18 16,000 gallons per minute (GPM) from the upstream side (north). Product would also
19 flow backwards from the downstream end (south) under great pressure and out of the
20 severed pipe until Enbridge isolated the leak. Even after the leak was isolated, product
21 would continue to flow from both ends of the pipe until the pressure of the isolated
22 product reached the hydrostatic pressure. Any product that is present at a pressure that

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1 exceeds the hydrostatic pressure would continue to flow into the surrounding rock,
2 sediment and water.

3
4 Product being released while the pipeline was still being pumped would have a force of
5 1440 psi which is several times greater than the pressure of a fire hose (typically 116-290
6 psi) and would easily jet away the highly fractured and brecciated rock and sediments
7 overlying the tunnel.

8
9 Product would move relatively rapidly outward and upward from the pipeline release
10 point as long as the pipeline was flowing, or the product pressure exceeded the
11 hydrostatic pressure. Once the pipeline flow stopped, and product pressure reached
12 equilibrium with the hydrostatic pressure, the active product flow would cease. However,
13 from this point on, the product would still migrate upward through fractured rock and
14 porous sediments in a relatively slow manner through the rock fractures and pore spaces
15 of the rock and sediments until a low permeability zone in the rock or sediments was
16 reached.

17
18 The product released to the rock and sediments above the tunnel would slowly migrate
19 upward through the saturated media because of differential pressure caused by the density
20 differential of the hydrocarbons and the water in the rock or sediment. The product is
21 lighter than water and would continue to move upward, displacing water in the fractures
22 and pores of the overlying rock and sediments as long as the buoyancy pressure exceeded
23 the capillary resistance of the water in the pores/fractures. The product would accumulate

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1 if or when it encountered a geologic seal or trap that prevented further upward migration.

2 If there is no trap, the product would continue to rise until it breaks through the lakebed
3 sediment and enters the water column.

4
5 Once in the water column, the product would rise as distinct separate light non-aqueous
6 phase liquids (LNAPLS) and float to the surface and/or be moved by the lake currents,
7 waves and wind. One gallon of product would contaminate one million gallons of water
8 and cover 8-acres of the lake surface. The floating hydrocarbons would eventually reach
9 the shores of the Straits and be carried far into both Lake Huron and Lake Michigan.

10
11 In addition to the migration of the mobile product, there would be an immobile fraction
12 that would remain stuck in the rock and sediments and slowly dissolve into the
13 groundwater, and ultimately the water column, for decades or possibly centuries.

14 Dissolved hydrocarbons are neutrally buoyant and travel with ground water or surface
15 water flow and can travel hundreds of miles when driven by currents and wave action.

16 These immobile product residuals would remain a long-term source of pollution in the
17 Straits.

18
19 **Q. Does this conclude your testimony?**

20 **A. Yes.**

EXHIBIT BMC-61

Brian J. O'Mara
Principal

<https://agateharbor.com>



Mr. O'Mara founded Agate Harbor Advisors LLC in 2020. He serves as a Principal Scientist and independent client advisor and technical expert providing strategic environmental consulting and litigation support to leading private and public sector clients in the agriscience, automotive, brownfields redevelopment and environmental liability transfer, chemical, legal, infrastructure, manufacturing, pharma, pulp and paper and waste management sectors. Mr. O'Mara has more than 30 years of experience in environmental consulting specializing in geotechnical and hydrogeologic investigations, tunnel and shaft permeation and consolidation grouting; tunnel and shaft construction, abandonment and removal; tunnel and shaft pre-design investigations; methane investigations, monitoring and mitigation; and hydrocarbon contaminant fate and transport, containment, capture and treatment solutions.

Mr. O'Mara has a proven track record of providing insightful and practical solutions to complex site investigation/remediation challenges and litigation support services for contaminated land and groundwater at hundreds of facilities across the Americas, Europe, and Asia. Some of these projects were regulated under Superfund, RCRA, TSCA, FIFRA or numerous state or federal (Non-US) remediation programs.

His public sector clients include the Detroit Water and Sewerage Department; Export-Import Bank of the United States; Maine DEP; MassDEP; MDEQ; Milwaukee Metropolitan Sewerage District; the US Air Force; US Army Corps of Engineers; and the USEPA. Private sector clients include 3M; AO Smith; BASF; Consumers Energy, CSX Transportation; Dana Holdings; DTE Energy; Dickinson Wright; Ford; General Electric; General Motors; Marathon Petroleum; Kirkland & Ellis; Koch Industries; Lockheed Martin; Miller Canfield; Northrup Grumman; Novartis and TRW Automotive.

Mr. O'Mara is an expert in the investigation and remediation of soil and groundwater impacts from industrial facilities in more than 40 US states and more than 40 countries globally. He lived and worked professionally for seven years on more than 50 soil and groundwater site investigation and remediation projects and a dozen water supply studies across Wisconsin. Several of these projects involved remote sensing, surface geophysical surveys, fracture trace analyses and large-scale aquifer pumping tests for municipal and industrial wells. He has experience working in Wisconsin sites underlain by carbonate bedrock including the Northeast, the Driftless Area of the Southwest and South-Central region, all with known sinkhole hotspots.

He has served as an expert witness and prepared expert reports for hydrogeologic investigation and remediation litigation as well as determining the remediation liabilities for hundreds of contaminated sites. He has served as Arbitrator, deciding a \$12 million-dollar remediation escrow dispute and has been deposed in multi-million-dollar tunnel construction disputes related to karst conditions.

Education

B.S. Geological Engineering,
Michigan Technological University

Graduate Studies: Environmental
Engineering and Hydrogeology,
University of Wisconsin-Milwaukee
and Wayne State University

Continuing Education: Grouting for
Tunnels and Shafts; Underground
Construction; Ventilation for
Tunnels and Shafts; Geotechnical
Instrumentation; Fractured Rock;
Acid Mine Drainage

Employment History

Principal, Agate Harbor Advisors
LLC – Grosse Pointe, MI 2020 to
present

Director, Power & Industrial
Solutions, Lone Wolf Resources,
LLC, 2020 to present

Energy Renewal Partners LLC –
Detroit MI 2017 to 2020

Principal-in-Charge, Ramboll, Ann
Arbor Michigan 2016-2017

Principal Engineer, SLR Consulting,
Detroit, MI 2015-2016

Vice President, Principal-in-Charge
ARCADIS, Detroit MI 2002-2015

Operations Manager, Weston
Solutions, Detroit MI 2001-2002

Principal-in-Charge, TRC Solutions,
Lowell, MA 1996-2001

Project Engineer, ChemCycle Corp,
Boston, MA 1993-1996

Engineer/Hydrogeologist, Earth
Tech, Milwaukee, WI 1991-1993

Hydrogeologist, Layne GeoSciences,
Inc., Pewaukee, WI 1990-1991

Resident Inspector and Staff
Engineer, Barrientos and
Associates, Madison, WI 1987-1990

License

License: Professional Geologist –
State of New Hampshire, License
No. 365 (active 2001 - 2010)

Brian J. O'Mara
Principal

<https://agateharbor.com>



Select representative experience related to tunneling, karst and litigation support is summarized below.

Tunnels and Shafts

Various Tunnel and Shaft Construction, Pre-Design Studies, Grouting and Methane Management Projects

Milwaukee Metropolitan Sewerage District – Multiple Tunnels and Shafts, Milwaukee County, WI

Resident Inspector, Staff Engineer and Geologist for MMSD Water Pollution Abatement Program \$1.2 Billion Deep Tunnel Program. Assigned full-time to the Program Management Office and Geotechnical Group led by CH2M Hill. Worked more than 10,000 hours on this program, almost all time was in the field and worked thousands of hours underground in various tunnels, shafts and ancillary structures.

Responsible for directing, overseeing and logging thousands of feet of bedrock core drilling to depths of more than 350 feet for tunnel and shaft construction and completed hundreds of borehole packer tests. Completed geologic mapping of more than nine miles of limestone and dolomite bedrock with extensive solution cavities, vuggy zones, solution cavities, faults, joints, bedding planes and other karstic features.

Responsible for permeation and consolidation grouting operations to limit groundwater infiltration into more than twenty miles of bedrock tunnels and shafts. Participated in large scale dye studies and other tracer studies and hundreds of completing hundreds of aquifer packer tests inside excavated tunnels. Responsible surface angle drilling and pre-grouting program to minimize groundwater infiltration prior to tunneling and shaft excavations.

Responsible for operation of groundwater recharge wells to mitigate and prevent damage to late 19th and early 20th century wooden pile foundations that were being damaged by lowered water tables resulting for groundwater inflow to the tunnels.

Evaluated and participated in various construction claim disputes for damages related to delays and cost overruns associated with the karstic conditions encountered during the tunnel construction.

Experience included the following tunnel and shaft contracts:

- Crosstown Phase IA Tunnel, Reed Street Shaft, County Stadium Shaft
- Crosstown Phase IIA Tunnel
- CT-8 Collector Tunnel
- CT-7 Collector Tunnel
- CT-5/6 Collector Tunnel
- Northshore Tunnel
- Kinnikinic Tunnel Main Shaft
- Lake Michigan Tunnel Main Shafts
- Jones Island Siphons

Brian J. O'Mara
Principal

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University of Wisconsin-Milwaukee – Grouting Practice for Tunnels and Shafts Short Course

UW Milwaukee – Milwaukee, WI

Co-developed and presented a short course for CEU credits for engineers, geologists, owners, contractors and consultants tasked with developing and implementing cementitious and chemical grouting programs to reduce groundwater infiltration into hard rock and soft ground tunnels and shafts.

MBTA Silver Line – Fort Point Channel Tunnel Crossing

Massachusetts Bay Transportation Authority – Boston, MA

Project Engineer developed pre-construction soil characterization and soil management plan to address potentially contaminated soil, sediment and industrial/commercial waste residuals along the tunnel alignment, including the sediments of the Fort Point Channel. The tunnel profile included standard cut and cover trenching technology for upland areas and immersed tube tunnel (ITT) sections for crossing the Fort Point Channel and Russia Wharf. The soil management plan was developed to be compliant with MCP requirements for managing contaminated media.

MWRA – MetroWest Water Supply Tunnel

Massachusetts Bay Transportation Authority – Boston, MA

Grouting Advisor to Resident Engineer (Sverdrup/Jacobs Civil) for \$655M, 17.6 mile, 16-ft diameter mined (14-ft dia finished) with depths of 200-500 ft. Reviewed soil boring, core logs and rock samples and made recommendations for pre- and post- tunneling grouting programs to reduce groundwater infiltration.

Macomb County Public Works – Ten Mile Drain Interceptor Tunnel PCB Matter

Public Works Department – St. Clair Shores, MI

Tunneling Advisor to Deputy Drain Commissioner, county engineering staff and engineering consultant. Reviewed technical reports and sampling data for PCBs in surface water sediments from nearby canals, sewer laterals, tunnel lining integrity and assess PCB sources, fate and transport for tunnel owner/operator. Provided assistance with USEPA and MDNRE liaison.

Upper Rouge CSO Tunnel

Detroit Water & Sewerage Department – Western Detroit, Wayne County, MI

Senior Consultant for proposed 7-mile-long tunnel designed to capture up to 201 million gallons of wet weather flows from existing sewer infrastructure in western Detroit from 17 designated outfalls that discharge to the upper tributary of the Rouge River. Developed SOW and led investigations for proposed drop shafts and other surface connections and to support Baseline Environmental Assessments. The 1.2 billion project was ultimately cancelled because of the projected rate increases and the high unemployment rate of the City in 2008.

Detroit River Tunnel Project

Confidential Investment Consortium – Detroit, MI and Windsor ON

Senior Consultant for investment consortium that wanted to develop a new tunnel under the Detroit River between Detroit and Windsor. Completed conceptual design and constructability studies, evaluated existing rail tunnel conditions, reviewed local geology and hydrogeologic hazards and historic

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tunnel project failures in southeast Michigan. The rail tunnel project was designed to move trucks through the existing 105-year-old rail tunnel and build a new larger tunnel for trains. But community resistance against trucks rolling through the middle of the city killed that part of the plan and the project reverted to a rail-only proposal which was not economically feasible at the time.

Former Mine Shaft Closure

Confidential Chemical Client – Upstate, NY

Owners Engineer review existing conditions and proposed plan and costs provided by consultant to backfill and cap this long abandoned shaft for a former non-metallic mine. Developed alternative closure plan that met State and Federal requirements but avoided backfilling the entire shaft – saving the client more than \$1M in closure costs.

Power Plant Cooling Water Tunnel and Coal Handling Tunnel Decommissioning

Former Consumers Energy J.R. Whiting Power Plant – Luna Pie, MI

Owners Engineer for responsible for decommissioning, abatement and demolition, remediation and redevelopment of the J.R. Whiting. Responsible for developing design and implementation of all cooling water and recirculation water tunnels, intake structures, screen houses and outfalls to Lake Erie. Also demolished and backfilled coal handling tunnels, reclaim tunnel hopper and shaft.

Power Plant Cooling Water Tunnel Decommissioning

Former Consumers Energy B. C. Cobb Power Plants – Muskegon, MI

Owners Engineer for decommissioning, abatement and demolition, remediation and redevelopment of the 313 MW B. C. Cobb power plant. Responsible for developing design and decommissioning of all cooling water and recirculation water tunnels, intake structures, screen houses and outfalls associated with this 1940s power plant.

Power Plant Cooling Water, Coal and Limestone Tunnel and Shaft Decommissioning

Former JEA St. Johns River Power Park – Jacksonville, FL

CQC Manager for \$17M decommissioning, abatement and demolition, remediation and redevelopment of the 1264 MW St. Johns River Park coal fired power plant including the closure of numerous stormwater and waste water impoundments and all coal, limestone and gypsum handling infrastructure – including numerous tunnels and shafts and thousands of feet of recirculation water tunnels over nearly 400-acres.

Power Plant Cooling Water Tunnel and Evaporation Impoundment Decommissioning

Confidential Client – Four Corners Area

Senior Advisor – Developed strategy, scope, quantities and cost estimates to close in place more than 14,000 feet of cooling water recirculation tunnels extending from four generating units to four cooling towers. Worked with specialty flowable fill subcontractor to use an on-site batch plant to produce 32,000 cubic yards of air entrained lightweight controlled low strength material (CLSM) to fill all the cooling water tunnels and the plus 5 miles of small diameter water supply lines to the plant. Also developed plan and costs to close by removal more than 200-acres of evaporation pond basins.

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Water Supply Tunnel Re-use and Decommissioning Evaluation

Water Supply Tunnel from Former Coal Fired Power Plant to Lake Diversion impoundment – Texoma Region. TX

Owners Engineer and Advisor to Environmental Risk Transfer Developer. Evaluated costs for rehabilitation and reuse as well decommissioning and abandonment of 60-mile-long water supply tunnel from Lake Diversion to a shuttered power plant as part of proposed redevelopment of the power plant.

Pumped Storage Power Plant and Water Supply and Cooling Water Tunnel Redevelopment

Former Navajo Generating Station - Page, AZ

Advisor to Environmental Risk Transfer Developer CQC Manager for decommissioning, demolition and redevelopment of the 2.25 GW Navajo Generating Station (NGS) power plant situated on 1020 acres near Page Arizona. Worked with the developer to develop plans to upgrade, and re-use existing water supply intake and tunnels for the former NGS as part of a Pumped Storage power supply for a block chain data center to be constructed as part of the redevelopment. Also responsible for development of strategy and cost for closure of coal combustion residuals landfill and impoundments.

Karst Investigations and Remediation

Large Scale Karst Investigation and Remediation

Meramec Caverns, Village of Oak Grove Well Superfund Site, Sullivan Landfill and TRW-Ramsay Plant Sullivan, MO

Principal in Charge, responsible for comprehensive remedial investigation and remediation responses at four sites in Missouri to address widespread TCE impacts identified dolomite and limestone aquifers where the effects of karst geology are pronounced. Impacts were found in municipal water supply wells, private domestic wells, springs and caves. The thin soils and thick deposits of unconsolidated decomposed bedrock allow for high rates of groundwater recharge. Much of the water that would ordinarily runoff into streams is channeled underground through losing streams and sinkholes. The Sullivan Landfill and TRW Ramsay plant where the only TCE sources identified. Impacts are seen more than 4 miles away in the Meramec Caverns. Investigations included installation of monitoring wells, completion of dye studies and tracer studies. Installed water treatment systems for the Village of Oak Grove water supply wells, Point of use treatment systems for private wells and air ventilation and treatment systems for the Meramec Caverns. The work was overseen by MoDNR and USEPA Region VII.

Hydrogeologic Investigation and Remediation in Area with Karst

Lehigh Portland Cement Company Superfund Site, Mason City IA

Project Hydrogeologist and Engineer for groundwater monitoring well and recovery well installations and groundwater sampling as part of RI/FS and RD/RA where more than 1,000,000 tons of cement kiln dust (CKD) had been disposed of in an abandoned limestone quarry on-site and an additional 400,000 tons of CKD disposed at the nearby Line Creek Nature Center. Environmental impacts include pH 13 groundwater and surface with elevated TDS, sulfates and metals. Impacts were found in the Devonian bedrock, but karst conditions were found to be limited and the fine-grained nature of the CKD help to minimize contaminant migration into the limestone. Helped developed remediation design that included

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dewatering of impacted areas, construction of an engineered clay cap and operation of the a groundwater hydraulic containment remedy to maintain an inward hydraulic gradient and limit off-site migration of shallow groundwater and prevent exacerbation of bedrock groundwater.

Karst Investigation and Remediation

Pfizer Pharmaceuticals, Barceloneta, Puerto Rico

Project Engineer and Geologist for RCRA Corrective Measures Study and RCRA Corrective Action to address historic releases of benzene and other VOCs from a large Tank Farm facility located over a buried limestone sinkhole that had collapsed and was filled with rock, soil and debris. Nitrogen drilling techniques were required because of the elevated VOC concentrations in the underlying soil and rock. Developed and managed a Soil Vapor Extraction (SVE) Pilot Test for the Tank Farm/Sink Hole and SVE was adopted as the remedy to address residual VOCs.

Karst Investigation and Bedrock Grout Curtain Remediation

Former Solvent Chemical Corp Superfund Site, Niagara Falls, NY

Remediation Engineer developed an alternative groundwater containment remedy (Bedrock grout curtain) on behalf of the environmental insurance underwriter (AIG) to reduce the predicted CAPEX and OPEX costs to limit off-site migration of chlorobenzenes and other organic compounds into the Lockport Dolomite bedrock which contains a series of laterally extensive horizontal fracture zones capable of transmitting large quantities of water. Groundwater in the bedrock is strongly influenced by water levels in the Niagara River. Vertical fracturing between the various bedrock zone and impacts were found to 150-feet deep.

Environmental Due Diligence for Transaction Support

Independent Environmental Consultant Report for Proposed Luxury Resort on Karst

Project Albany, New Providence, Nassau, Bahamas

Technical Lead and Client Advisor responsible for completion of Independent Environmental Consultant Report on behalf of the Export-Import Bank of the United (lender to the Tavistock Group) for the proposed 600-acre, \$600-million luxury resort development in accordance with IFC World Bank EHS Guidelines and Performance Standards. The proposed development included a golf course, equestrian stables, paddocks and riding park; a deep-water harbor for mega yachts and luxury hotel and condos. The site development proposed risk to the shallow freshwater aquifer which was present in karst bedrock with little to no soil cover. Evaluated hydrogeologic risks related to fertilizers/pesticides of the golf course and equestrian operations, fuel storage facility and water treatment plant and the effects on groundwater quality, salt water intrusion and the presence and proximity of sink holes, blue holes and other karst features on or near the proposed development. Prepared comprehensive report for the Ex-Im Bank and made recommendations for additional environmental monitoring, protections and mitigation measures related to the proposed development. The project eventually received the necessary permits and funding and is one the most exclusive resorts in the world.

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Hydrocarbon Investigations and Remediation

Diesel Fuel LNAPL Product Investigation and Remediation

CXST – Toledo Docks, Oregon, Ohio.

Senior Engineer provided technical review of LNAPL delineation, product bail down tests, site hydrogeology and historic LNAPL thickness and extent and groundwater flow maps. Developed remedial strategy to show that residual LNAPL was largely the immobile fraction and off-site migration of free product was unlikely and a case could be made for MNA only, followed by NFA.

Confined Fuel Oil LNAPL Product Investigation and Remediation

Confidential Automotive Client – Dreux, France

Principal-in-Charge – worked with in-house LNAPL subject matter expert and other from local (French) project teams to demonstrate observed increase in apparent and actual product thickness was the result of confined LNAPL condition for wells screened in a fractured chalk aquifer. Bail down tests demonstrated that the product was nearly 100 percent immobile fraction and off-site migration of free product was unlikely and the French authorities (DREAL) approved a No Further Action decree as the hex-chromium and TCE Plumes had already been successfully bioremediated.

Gasoline Station LUST Removal, Investigation and Remediation Projects

Confidential Client – Various Site, WI and IL

Field Engineer and Hydrogeologist – responsible for directing removal of USTs and ancillary piping at more than two operating gasoline stations across Wisconsin and Illinois. Responsible for collecting soil and groundwater samples to demonstrate clean closure or define the nature and extent of contamination. Installed soil boring, monitoring wells, conducted slug test, bail down test, shake test and other methods to measure LNAPL thickness. Installed SVE, AS, bioslurping, biosparging, active and passive free product recover systems and in-situ bioremediation or MNA to achieve regulatory closure

Fuel Oil UST Removal, Investigation and Remediation Projects

Confidential Client – Dearborn, MI

Principal – responsible for leading fast-track removal and subsequent investigation and limited remediation of 40,000-gallon fuel oil UST for a client that was exiting a long-term lease and needed a No Further Action letter from the MDEQ prior to termination of the lease. While the UST was intact, there was evidence of minor overfilling and some visible product and sheen present on the water table. Over-excavated impacted soil and recovered floating product with a vacuum truck over a 5 day period until there was no visible product remaining and groundwater samples were below criteria. Prepared Part 213 UST Closure Assessment and Remediation documentation and MDEQ accepted the findings of the report.

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Litigation and Alternative Dispute Resolution

Expert Report & Testimony – Major Permit Modification Contestation

Cell "M" Groundwater Evaluation Expert Report EnviroSAFE Services of Ohio, Inc. (ESOI), Oregon, Ohio.

Provided Expert Testimony when deposed and cross-examined by attorneys for the City of Oregon Ohio (Plaintiff), ESOI (Defendant), OEPA and Attorney General for the State of Ohio in relation to various longstanding disputes between the parties over environmental contamination found at the hazardous waste treatment and disposal facility. ESOI wanted to significantly expand vertically their existing Cell M RCRA C Landfill Prepared expert report on the occurrence of groundwater with the various geologic units at the Site which includes both historic and operating hazardous waste landfills. ESOI and OEPA suggested the upper and lower tills contained isolated connate glacial water and are incapable of supplying useable water volumes to wells due to low horizontal and vertical permeabilities and the upper till is not hydraulically connected to overlying lacustrine deposits and the tills are not fractured or capable of transmitting significant quantities of groundwater.

Demonstrated that the existing groundwater level data, analytical chemistry results and numerous published sources do not support the opinions of OEPA and ESOI. Demonstrated water levels at the Site exceed the bottom elevation of the Cell M Landfill Primary liner and pose a significant risk to the performance of the landfill liner. Demonstrated the proposed expansion did not satisfy the requirements of the GeoRG Manual and additional geotechnical stability analyses were required. Showed that the upper till and lower till were not homogeneous, massive impermeable clays incapable of transmitting groundwater but were actually, heterogenous, fractured, and capable of transmitting groundwater at rates many orders of magnitude greater than reported in the Permit Modification. Demonstrated that portions of the clay liner are in direct contact with site groundwater and over time the clay portion of the liner will become saturated and highly ineffective at preventing diffusion of contaminant directly from the landfill into groundwater. The City eventually settled numerous disputes with EOSI and OEPA and prevailed in getting the concessions and revisions they requested for the Permit Modifications.

Hydrocarbon Remediation Escrow Dispute Arbitration and Expert Report

Warren E. Gast and RDV Aria LLC v IDEX Corporation, State of Michigan, Circuit Court of Kent, County Michigan, Case No. 04-08730-CK Hon. Paul J. Sullivan Two Western Michigan Industrial Facilities

Selected as the Technical Arbitrator after attorneys for the parties in dispute interviewed two other remediation experts from Arcadis (both with PhDs and co-authored Remediation Hydraulics textbook) based on Mr. O'Mara's practical experience with remediation and transactions. Teamed with Environmental Attorney as part of two-person panel to settle a remediation escrow dispute over chlorinated solvent impacts to soil and groundwater. Defendants and Plaintiffs' attorneys argued their respective cases and engaged more than a dozen of technical experts (environmental engineers and hydrogeologists, risk assessors) which provided four days of testimony and cross-examination by the attorneys and arbiters. Reviewed more than 99 exhibits to assess the completeness and effectiveness of the hydrogeologic investigation and groundwater remediation work completed and the terms of the M&A contract. Had to make a technical assessment of both costs that had been incurred over ten years plus develop independent estimate of likely future costs required to achieve regulatory closure. Coauthored 12-page Decision and Award document which described the nearly \$4MM award to the Defendant and release of the remaining escrow funds to the Plaintiffs.

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Expert Report on Environmental Liabilities

Detroit Steel Company Tax Appeal Matter (Trenton Land Holdings, LLC and Detroit Steel Company, LLC v City of Trenton, Michigan Tax Tribunal Docket No. 0394858)

Provided expert opinion on previously prepared work products and prepared independent estimates of environmental liability for a 195-acre former McLouth Steel Mill site in Trenton, MI. Work involved a comprehensive review of relevant technical documents, and inspection of the facility, interviews with individuals with knowledge of the site and an analysis of findings and preparation of the opinion of costs related to environmental liability issues that must be addressed in order to achieve compliance with environmental laws and regulations. Site is situated on the Detroit River and had extensive soil and groundwater contamination related to the more than 60 years of steel making operations, beginning in 1948. Remediation liabilities ranged from over \$23 million to more than \$33 million.

Expert Services Concentrated Animal Feeding Operations (CAFO) Permitting Contestation

Confidential Client – Ongoing Litigation Support

Providing expert review of the geology, hydrogeology, groundwater quality, contaminant fate and transport and vulnerability of surface water and groundwater from proposed CAFOs and nearby fields where CAFO waste would be applied. Will prepare expert reports and testimony as required for ongoing CAFO permit applications in Great Lakes region.

Tunnel Grouting Construction Dispute Resolution - Related to Karst Conditions

Dillingham Healy Grow & Dew JV v MMSD; Traylor Brothers, Inc. v MMSD; Layne Western, Inc. v MMSD

Provided testimony, fieldnotes, and other documentation and opinions as Resident Inspector and Staff Engineer/Geologist directing tunnel grouting in the Crosstown Interceptor and NorthShore Tunnel over disputes between the grouting contractors and the owner (MMSD). The contractors claimed the extreme karst conditions present in the tunnels and shafts represented Differing Site Conditions (DSC) and were entitled to claims for millions of dollars in additional compensation for damages related to out of scope quantities, material and labor. All cases were settled out of court.

Natural Resources Damage Assessment Claim Dispute Resolution

Confidential Insurance Underwriter and Policy Holder - Long Island Sound Environmental Damages related to Hydrocarbon Release

Principal Scientist reviewed \$1B insurance claim prepared by A.D Little related to ongoing Natural Resources Damage Assessment (NRDA) case where linear alkyl benzene dielectric fluid was released from electric transmission cables on the sea floor of Long Island Sound. Most of the NRDA was related to claims related to losses from commercial and recreational oyster and clam fishermen as well as impacts to other natural and ecological receptors affected by the release. Developed independent cost estimate and helped Insurer to successfully negotiate an out of court resolution.

Environmental Remediation Claim for Manufactured Gas Plant Portfolio

Confidential Insurance Underwriter and Policy Holder - Various East Coast and Midwest States

Principal Scientist reviewed \$600 Million claim related to more than 100 former manufactured gas plant (MGP) sites located in the Northeast, Mid-Atlantic and Midwest states. Sites had been contaminated by coal tar and other residuals including ferrocyanide, mercury, VOCs and PAHs. Claimant had grossly overestimated the anticipated costs to achieve regulatory closure and no further action. Developed independent cost estimates and remediation compliance strategy that helped Insurer to successfully negotiate an out of court resolution.

EXHIBIT BMC-62

**NINTH DISCOVERY REQUESTS TO ENBRIDGE ENERGY, LIMITED PARTNERSHIP BY
MICHIGAN PUBLIC SERVICE COMMISSION STAFF (MPSC)**

Utility Information Request

Public Document

Docket Numbers: Case No. U-20763

Date of Request: November 15, 2022

Requested From: Enbridge Energy, Limited Partnership

Response Due: December 1, 2022

Objections and Response By: Michael Ashton, Legal Counsel

| Request No. | |
|-------------|---|
| 9(12) | |
| Request: | <p>Please provide information in response to the request on page 45 of the Commission's July 7th order:</p> <p><i>"However, there is no information on the record regarding the concrete's ability to withstand the effect of a high-pressure air impact from an explosion."</i></p> |
| Objections: | <p>Enbridge objects based on the following:</p> <ol style="list-style-type: none">1) This request mischaracterizes a statement from the July 7, 2022 Order as a "request".2) This request exceeds the scope of information the Commission found in its July 7, 2022 Order that Enbridge should file.3) This request is unduly burdensome and seeks to have Enbridge locate documents or information which are not proportionate to the needs of the case. |
| Response: | <p>Notwithstanding the foregoing objections, please see Enbridge's response to Additional Information Requested by the Commission No. 10. Further stated, please see pages 46 and 47 of the Commission's July 7, 2022 Order for the listing of additional information which the Commission found that Enbridge should file to support the Commission's prong (3) of its 1929 PA 16 analysis and which specifically lists ten (10) categories of information. The quoted sentence from page 45 of the Commission's July 7, 2022 Order is not found within the set of information the Commission found that Enbridge should file as set forth on pages 46 and 47 of the Commission's Order.</p> |

EXHIBIT BMC-63

Brian J. O'Mara Testimony - Supporting Calculations

Volume of Air in Tunnel

$$V = \pi r^2 * L = \pi * (\text{radius of tunnel in feet squared}) * \text{length of tunnel in feet}$$

$$V = 3.14 (10\text{ft})^2 * 21,200\text{ft} = 6,656,800\text{ft}^3 \text{ which is approximately } (\sim) 6,600,000\text{ft}^3$$

Assumed nominal diameter of tunnel is 20 ft (21 ft bore minus 6 in tunnel lining = 20 ft finished diameter)

Line 5 Product Flow Rate in Pipeline

$$Q = \text{Product Flow} = \text{Volume}/\text{time}$$

$$Q = 540,000 \text{ barrels per day (bpd)} \text{ (Source: Enbridge)}$$

Convert bpd into gallons per minute (gpm)

$$1 \text{ barrel} = 42 \text{ gallons}$$

$$540,000 \text{ bpd} * 42 \text{ gallons/barrel} * 1 \text{ day}/24 \text{ hours} * 1 \text{ hour}/60 \text{ min} = 15,750 \text{ gal}/\text{min} \sim 16,000 \text{ gpm}$$

Line 5 Release Detection Threshold

Enbridge states they could "detect a release of 2 percent or more of their shipped volume"

Enbridge state the shipped volume is 540,000 barrels per day

$$2 \text{ percent of } 540,000 \text{ bpd} = (0.02) * 540,000 \text{ bpd} = 10,800 \text{ bpd}$$

Convert bpd to gallons/day (gpd)

$$10,800 \text{ bpd} = 10,800 \text{ bpd} * 42 \text{ gallons}/\text{day} (\text{gpd}) = 453,600 \text{ gpd}$$

$$453,600 \text{ gpd} = 453,600 \text{ gpd} * 1 \text{ day}/24 \text{ hours} * 1 \text{ hour}/60 \text{ min} = 315 \text{ gpm}$$

External (Hydrostatic) Pressure Conversion

Tunnel will be subjected to up to 17 bar external pressure

(source: U-20783 Exhibit S-16, Witness D. Adams, McMillen Jacobs Associates)

Convert 1 bar to 1 standard atmosphere

$$1 \text{ bar} = 1.01325 \text{ standard atmosphere (atm)}$$

$$17 \text{ bar} = 17.225 \text{ atm}$$

Convert pressure in atmospheres to pounds per square inch (psi)

$$1 \text{ standard atmosphere (atm)} = 14.6959 \text{ psi}$$

$$17.225 \text{ atm} = 17.225 \text{ atm} * 14.6959 \text{ psi} = 253.1 \text{ psi} \sim 250 \text{ psi}$$

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of Enbridge
Energy, Limited Partnership for Authority to U-20763
Replace and Relocate the Segment of Line 5
Crossing the Straits of Mackinac into a Tunnel ALJ Christopher Saunders
Beneath the Straits of Mackinac, if Approval is
Required Pursuant to 1929 PA 16; MCL 483.1
et seq. and Rule 447 of the Michigan Public
Service Commission's Rules of Practice and
Procedure, R. 792.10447, or the Grant of other
Appropriate Relief

TESTIMONY OF PRESIDENT WHITNEY B. GRAVELLE

ON BEHALF OF

BAY MILLS INDIAN COMMUNITY

February 3, 2023

**PRES. WHITNEY B. GRAVELLE
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763**

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PRES. WHITNEY B. GRAVELLE
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

1 **I. INTRODUCTION & BACKGROUND**

2 **Q. Please state for the record your name, job title, and business address.**

3 A. My name is Whitney B. Gravelle. I am the duly elected President of Gnoozhekaaning,
4 “Place of the Pike,” or the Bay Mills Indian Community, which is a federally recognized
5 Indian Tribe with a government organized under the provisions of the Indian
6 Reorganization Act of 1934, 25 U.S.C. §5101, et seq. Bay Mills Indian Community is
7 located at 12140 West Lakeshore Drive in Brimley, Michigan.

8
9 Additionally, as a woman of Anishinaabe culture, I am a water keeper, which means I am
10 responsible for maintaining and protecting water for my people, praying to the water, and
11 caring for the water during ceremonies. Women carry sacred water teachings and pass them
12 on to the next generation. I actively seek teachings with elders and medicine carriers within
13 Bay Mills Indian Community, and help coordinate cultural trainings, sweat lodges, feasts,
14 and opportunities to gather traditional medicines amongst our tribal community.

15
16 **Q. Please state your educational background.**

17 A. I earned a Bachelor of Arts of Interdisciplinary Studies in Social Science from Michigan
18 State University with an emphasis in Political Science and East Asian Studies. I earned my
19 juris doctor, cum laude, from Michigan State University Law School. I also completed an
20 indigenous law certificate.

PRES. WHITNEY B. GRAVELLE
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

1 **Q. On whose behalf is this testimony being offered?**

2 A. I am testifying on behalf of Bay Mills Indian Community. This testimony reflects my
3 knowledge, expertise and experiences as the current President of Bay Mills, a former Chief
4 Judge of Bay Mills Tribal Court, former in-house counsel for the tribe and a lifelong citizen
5 of Bay Mills.

6

7 **Q. Please summarize your experience in tribal government.**

8 A. I have worked in tribal government for 7 years. On March 18, 2021, I was elected President
9 of Bay Mills, and I was sworn into office on March 19, 2021. Prior to being elected
10 President, I served as in-house counsel for Bay Mills from December 2018 to March 2021.
11 I also served as chief judge for the Bay Mills Tribal Court from November 2017 to
12 December 2018. I also taught tribal law at Bay Mills Community College from September
13 2019 to December 2022.

14

15 In my role as President, I represent Bay Mills by serving on the Chippewa Ottawa Resource
16 Authority, the Great Lakes Indian Fish and Wildlife Commission, the Inter-Tribal Council
17 of Michigan, the United Tribes of Michigan, and also represent indigenous communities
18 and perspectives by sitting on the Michigan Advisory Council on Environmental Justice. I
19 also serve on the Department of Interior's Secretary's Tribal Advisory Committee as
20 primary representative of the Midwest Region and as acting Chair.

PRES. WHITNEY B. GRAVELLE
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

1 **Q. Have you testified about Bay Mills’ interests before this Commission or in any other**
2 **proceeding?**

3 A. I have previously submitted direct and rebuttal testimony to the Commission in this matter.
4 In my role as President of Bay Mills, I have testified before Michigan Senate’s Energy and
5 Technology Committee.

6
7 **Q. Is the direct and rebuttal testimony that you previously submitted to the Commission**
8 **in this matter still true and correct?**

9 A. Yes.

10

11 **Q. What is the purpose of your testimony today?**

12 A. I am testifying on behalf of Bay Mills to respond to the testimony of John Godfrey and his
13 accompanying expert report that purports to examine the risks of Enbridge’s proposed
14 tunnel project.

15

16 **II. RESPONSE TO TESTIMONY OF JOHN GODFREY AND THE USE OF**
17 **QUANTITATIVE RISK ANALYSIS TO EVALUATE THE PROPOSED TUNNEL**
18 **PROJECT**

19 **Q. Did you review the testimony of Mr. John Godfrey submitted by Enbridge in the**
20 **remand phase of this case?**

21 A. Yes.

PRES. WHITNEY B. GRAVELLE
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

1 **Q. And are you familiar with Mr. Godfrey’s conclusions that a release within the tunnel**
2 **will occur once in 663,000 years and, further, that an ignition event within the tunnel will**
3 **occur once every 169 million years?**

4 A. Yes.

5
6 **Q. How do you, as a tribal leader and Anishinaabe woman, respond to that conclusion?**

7 A. Mr. Godfrey’s analysis, which attempts to quantify the risk of events occurring that could
8 lead to an explosion within the proposed tunnel, fails to address, or even acknowledge, the
9 impact of such an event – even if that event only occurred once.

10
11 A release from the pipeline or an explosion inside the tunnel would be terrifying. It would
12 have a profound and long-lasting impact on Bay Mills because it would cause catastrophic
13 damage to the waters of the Straits of Mackinac, Lake Michigan, and Lake Huron. Such
14 damage would cause incalculable harm to the citizens of Bay Mills who depend on the
15 waters in and around the Straits for their economic livelihood, their quality of life, their
16 cultural and aesthetic wellbeing, and their existence. An explosive event in the proposed
17 tunnel would, quite literally, be an assault on our entire way of life. Mr. Godfrey’s
18 testimony and report does not consider these consequences, let alone that they will be
19 experienced most acutely by Bay Mills and other tribal nations in the region.

20
21 **Q. How does your role as an Anishinaabe woman inform your response to Mr. Godfrey’s**
22 **testimony?**

23 A. The Straits are part of Bay Mills’ creation story. The Anishinaabe water keepers have been

PRES. WHITNEY B. GRAVELLE
DIRECT TESTIMONY ON REMAND - CASE NO. U-20763

1 protecting the waters in and around the Straits for thousands of years and future generations
2 will do the same.

3
4 Because our profound connection to the water has existed since our creation, my concerns
5 about the tunnel are not alleviated when someone states that a release into the Straits is
6 unlikely. Stating that it could happen *once* within 169 million years does not negate that
7 fact that if it could happen and that it could happen in year one of operation, or year two of
8 operation, or year 99 of operation. All it will take is one release to cause untold destruction
9 in the Straits. Godfrey's report ignores the consequences of such an event and fails to
10 acknowledge that any "low probability" analysis must be balanced by the high
11 consequences of the event.

12
13 **Q. And, in your role as an Anishinaabe woman, what do the high consequences of a**
14 **release mean to you?**

15 A. In our Anishinaabe culture, from a young age women are given teachings by elders,
16 medicine men, and medicine women in our Tribal Nation that describe how we are meant
17 to carry out our lives in a way that aligns with our seven grandfather teachings, seven
18 generations teachings, and treaty teachings. These teachings all start with creation, and all
19 creation begins with water. Therefore, water is a long-standing relationship and the first
20 relationship that we form - from water in the womb, to the water we drink, to the water that
21 grows our food, or the water that cares for animals, it is a symbiotic interrelationship
22 between all living beings. It is a very real connection that if impacted, creates a chain
23 reaction that then affects every other relationship, because you cannot have one exist on its

PRES. WHITNEY B. GRAVELLE
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1 own without the others.

2

3 If those relationships are impacted by a spill from Line 5 in the Straits of Mackinac, it can
4 only mean loss. A loss of oneself, a loss of one's past and future, a loss of one's culture,
5 and a loss of one's Tribe. My people, Bay Mills Indian Community, have had a
6 longstanding historical relationship with the land and water in and around the Straits of
7 Mackinac since time immemorial, through treaty times, until present day. If that
8 relationship is severed it can only mean that my people no longer have the ability to survive
9 in this area any more – they could not hunt, they could not fish, they could not gather, they
10 could not perform ceremony, they could not pass on teachings, and they could not use
11 medicines to heal themselves. The list goes on and on. All it takes is one time and one spill
12 to destroy my people and destroy all that we hold dear.

13

14 Because that destruction means loss, it is even more important that as a water keeper and
15 as a Tribal Nation we do all that we can to protect the Straits of Mackinac from even *one*
16 spill. Safeguarding and protecting water means honoring water and its role in creation,
17 uplifting it and respecting it as more important than even yourself. Because water will
18 provide for my *indaanikoobijigan*, my future ancestors.

19

20 **Q. Does the testimony of Mr. John Godfrey alleviate any concerns you previously**
21 **expressed about Enbridge's proposed route of the tunnel project through the Straits?**

22 A. No. While Mr. Godfrey's probability analysis relies on historical data sets that minimize
23 the risks associated with the tunnel, my consideration of history points to the opposite

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1 conclusion. The history of pipeline operations in this country is replete with examples of
2 ruptures, leaks and explosions that have had devastating impact. Undoubtedly, these events
3 were regarded as highly unlikely to happen. And, too often, indigenous people bear the
4 brunt of such accidents.

5
6 Far from alleviating my concerns, Mr. Godfrey's testimony exacerbates them because it
7 does not address the perspectives of the tribes who will be directly affected by a release or
8 catastrophic explosion, the risk of which he attempts to minimize.

9

10 **Q. Does that complete your testimony?**

11 **A. Yes.**

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of Enbridge Energy, Limited Partnership for the Authority to Replace and Relocate the Segment of Line 5 Crossing the Straits of Mackinac into a Tunnel Beneath the Straits of Mackinac, if Approval is Required Pursuant to 1929 PA 16; MCL 483.1 et seq. and Rule 447 of the Michigan Public Service Commission’s Rules of Practice and Procedure, R 792.10447, or the Grant of other Appropriate Relief

U-20763

ALJ Christopher S. Saunders

PROOF OF SERVICE

On February 3, 2023, an electronic copy of *Testimony and Exhibits of Richard B. Kuprewicz, Brian J. O’Mara, and President Whitney B. Gravelle on behalf of Bay Mills Indian Community* was served on the following parties:

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