National Transportation Safety Board
Washington, D.C. 20594

Office of Railroad, Pipeline and Hazardous Materials Investigations

Pipeline Operations / Integrity Management

Group Chairman's Factual Report of the Investigation

Enbridge Inc.

Natural Gas Pipeline Rupture and Fire

Hillsboro, Kentucky

May 4, 2020

NTSB Investigation No.:

PLD20LR001

Report Date: December 17, 2021

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B. Accident Summary

For a summary of the accident, refer to the *Accident Summary* report within this docket.

C. Location of the Accident

On Monday, May 4, 2020, at about 4:36 p.m., an interstate natural gas transmission pipeline owned and operated by Enbridge Inc. (Enbridge) ruptured, resulting in a subsequent fire in a Class 1 location about 3 miles east-northeast of Hillsboro, Kentucky.[2] The failure occurred on Texas Eastern Transmission (TET) Line 10 at a location that had been previously identified by Enbridge for geotechnical monitoring and mitigation due to an active landslide.[3,4] The elevation profile and burned area are shown in Figure 1.

At the time of the accident, the temperature was about 70 degrees Fahrenheit, and it was not raining. No significant seismic activity was recorded near the accident location in the week prior to the accident.[5]

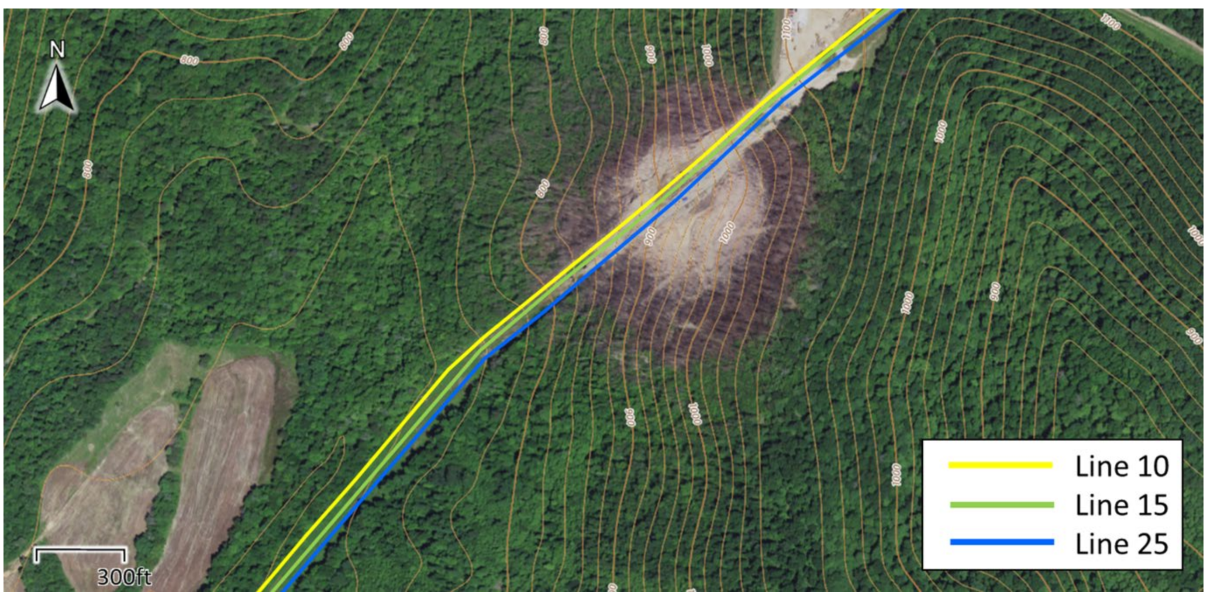

Figure 1. Location of Accident Near Hillsboro, Kentucky[6]

[2] (a) All times in this document are local time unless otherwise noted.
(b) *Class locations* are defined in Title 49 CFR 192.5 and range from one to four. Class location is defined based on the number and type of buildings within 220 yards of each side of the pipeline, with Class 1 locations representing the least populated areas, and Class 4 locations representing the most populated areas.
[3] Line 10 Alignment Sheets
[4] Geotechnical Causation Report by BGC Engineering USA Inc.
[5] Meteorology Specialist's Factual Report
[6] https://apps nationalmap.gov/viewer/ (Accessed October 27, 2021)

D. Description of the Operator

Enbridge is an energy corporation with three core businesses: natural gas transmission and midstream, crude oil and liquids pipelines, and utilities.[7] It is headquartered in Calgary, Canada, and employs more than 12,000 people, primarily in Canada and the United States. In the natural gas pipeline sector, Enbridge transports about 20% of the natural gas consumed in the United States through their transmission assets.[8] Enbridge owns, wholly, jointly or in part, several major natural gas transmission pipelines, including: Algonquin Gas Transmission, East Tennessee, Gulfstream, Maritimes & Northeast Pipeline, NEXUS Gas Transmission, Sabal Trail, Southeast Supply Header, TET, Valley Crossing Pipeline, and Vector Pipeline. The Enbridge asset involved in this accident, TET, connects Texas and the Gulf Coast with the northeastern United States.[9]

TET is a wholly owned subsidiary of Spectra Energy Partners, LP (Spectra), which is a wholly owned subsidiary of Enbridge. Prior to being owned by Spectra, TET was part of Duke Energy Gas Transmission, Panhandle Eastern Corporation, and Texas Eastern Corporation (Table 1).[10] TET operates a 8,580-mile transmission pipeline system (Figure 2). The peak transport capacity on TET is 13.05 billion standard cubic feet per day (Bcf/d). TET also has an associated 74 Bcf of natural gas storage. TET is an interstate natural gas transmission pipeline and is federally regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA).[11]

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[7] *Midstream* activities include the processing, storing, transporting and marketing of oil, natural gas, and natural gas liquids.
[8] https://www.enbridge.com/about-us
[9] https://www.enbridge.com/About-Us/Natural-Gas-Transmission-and-Midstream.aspx
[10] Information from SEC public filings.
[11] (a) Interstate natural gas pipelines transport natural gas across state boundaries.
(b) https://www.enbridge.com/map#map:infrastructure,search=%22Texas%20Eastern%22 (Accessed October 1, 2021)

Table 1. Ownership history for Texas Eastern Transmission

Owner of Texas Eastern Transmission[12]	Time Period	Ownership Type
Original incorporators and stockholders; Texas Eastern Corporation	01/30/1947 – 06/28/1989	Direct
Panhandle Eastern Corporation (acquirer of Texas Eastern Corporation)	06/29/1989 – 07/28/1994	Indirect
Panhandle Eastern Corporation/PanEnergy Corp	07/29/1994 – 04/15/2001	Direct
Duke Energy Gas Transmission Corporation (DEGT) (and successor Duke entities)	04/16/2001 – 01/01/2007	Direct
Spectra Energy Corp (now known as Spectra Energy, LLC)	01/02/2007 – 10/31/2013	Indirect
Spectra	11/01/2013 – present	Indirect
Enbridge (current indirect owner of Spectra)	02/27/2017 - present	Indirect

[12] Texas Eastern Transmission Corporation is now known as Texas Eastern Transmission, LP (TETLP)

Figure 2. Map of Texas Eastern Transmission[13]

[13] https://www.enbridge.com/map#map:infrastructure,search=%22Texas%20Eastern%22 (Accessed October 1, 2021)

E. Personnel Information

Enbridge's Gas Control personnel were responsible for monitoring and controlling line pressures and product flow rate and operating remote controlled valves and compressor stations. In the event of a leak, Gas Control was directed to dispatch field personnel to make an assessment and begin response efforts.[14]

Gas Control was based in Houston, Texas and field personnel were based near Hillsboro, Kentucky. The Director of Gas Control had worked on TET for about 26 years at the time of the accident and was responsible for overseeing Gas Control. The Director of Gas Control had three gas control managers that reported to him. Six gas controllers worked on each 12-hour shift and were collectively responsible for operating 13 pipelines. Each newly hired gas controller was required to go through an internal training program prior to going through the more formal Operator Qualification (OQ).[15] The OQ requirements included computer-based training and a knowledge and skills assessment given by the manager. Once the onboarding was complete, gas controllers were required to complete periodic training at least annually. At the time of the accident, Gas Controller A was responsible for operating assets from Egypt, Mississippi, to Western Pennsylvania, including the pipeline segment involved in this accident.[16]

Gas Controller A had worked on TET for about 14 years at the time of the accident. He was performing his normal gas control responsibilities at the time of the accident.[17] Five other Gas Controllers, Gas Controllers B-F, were working at the time of the accident and supported the response when needed.[18]

Field personnel involved in the response to this accident included the Owingsville Area Supervisor and his six employees and the Wheelersburg Area Supervisor and his five employees. The six employees from the Owingsville Area included the Station Operator, Electrical Control Technician, Light Equipment Operator, Utility Pipeliner A, Utility Pipeliner B, and Station Mechanic.[19]

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[14] Excerpt - Enbridge Stanford Area Emergency Response Plan

[15] Individuals performing covered tasks on a pipeline facility are required to meet minimum requirements for operator qualification in accordance with 49 CFR Part 192, Subpart N, *Qualification of Pipeline Personnel*.

[16] Director of Gas Control interview

[17] Gas Controller A interview

[18] For disambiguation, employees with the same title have an alphabetical designation added to their title (e.g., "A," "B," "C") to uniquely identify employees who hold the same position within the company.

[19] A *pipeliner* is a common job title in the natural gas transmission industry. Pipeliners are technicians who work in operations and maintenance, typically performing tasks such as operating valves and participating in general maintenance activities.

F. The Impacted Gas Transmission System

The bi-directional pipeline involved in this accident transported natural gas between Kosciusko, Mississippi and North Union Township, Pennsylvania. The 30-inch diameter Line 10 is one of three parallel pipelines operated by Enbridge along the same right-of-way.[20] The other two pipelines are the 30-inch Line 15 and the variable diameter Line 25. At the accident site, Line 10 was the northern-most of the three pipelines.[21]

The rupture occurred at a girth weld on Line 10, approximately 7.8 miles northeast of Owingsville Compressor Station (CS) (Figure 3). The failed girth weld had two associated identification numbers, "BHGE HW 12752961" and "EN WN 11330," and was located at an elevation of approximately 923.35 feet. This failed girth weld location corresponds to station 26921 + 67 (Mile Post 509.876) on Enbridge alignment sheets.[22]

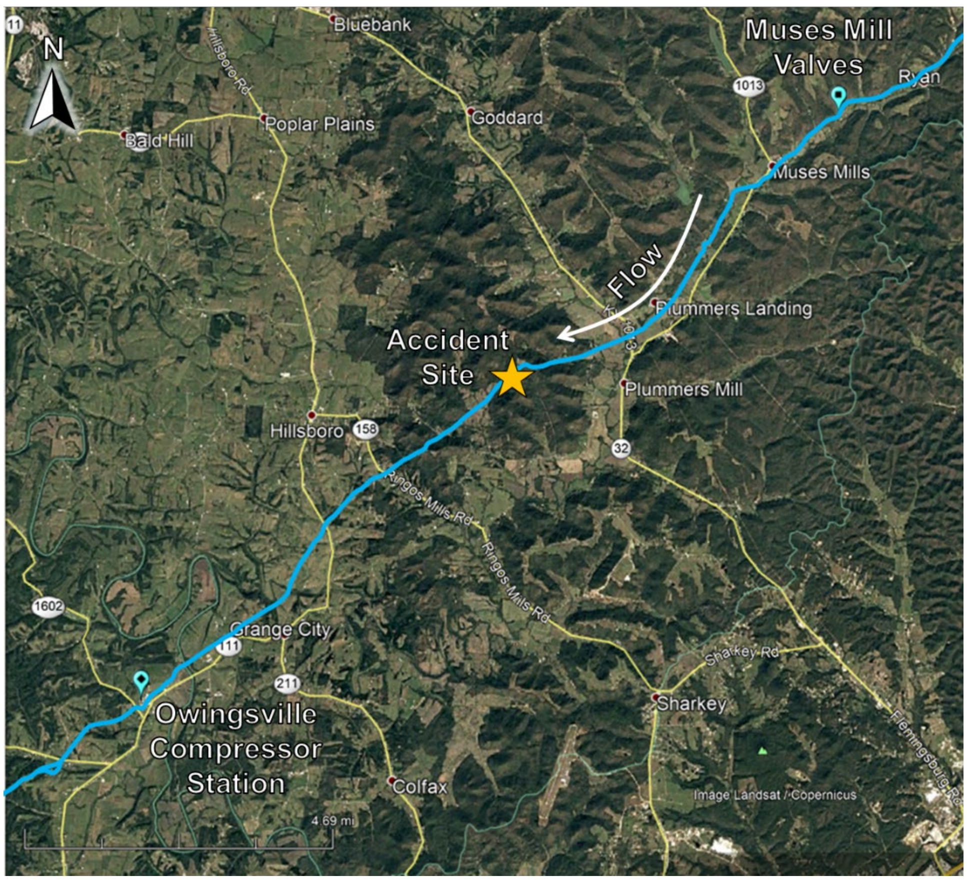

Figure 3. Map of TET Near Accident Site[23]

[20] Near the location of the accident, these three lines share the same right-of-way; there are locations where they do not.
[21] Basic System and Incident Information - Enbridge Responses to PHMSA Information Requests
[22] Station numbers vary between alignment sheets, as-built drawings, and in-line inspection results.
[23] https://pvnpms.phmsa.dot.gov/PublicViewer/ and Google Earth

F.1 Pipeline Information

The portion of Line 10 involved in the accident was manufactured by National Tube Company in 1951 and installed in 1952.[24] Line 10 was cathodically-protected with impressed current.[25]

The pipeline material was carbon steel with a specified minimum yield strength of 52,000 psi and coated with coal tar.

The portion of Line 10 involved in the accident was hydrostatically tested during original construction in 1952. This section of Line 10 was hydrostatically retested in 1986.

Enbridge did not locate records that indicated the original depth-of-cover for Lines 10, 15, or 25.[26] The depth of cover of Lines 10, 15, and 25 was previously measured during a close interval survey (CIS) on August 17, 2018. Based on the GPS coordinates and depth measurements provided in the CIS report, the depth of cover near the accident location was 84-86 inches, 58 inches, 53-84 inches for Lines 10, 15, and 25, respectively.[27]

Table 2. Pipeline Specifications for Line 10 at Accident Location

Description	**Value**
Year of manufacture[24]	1951
Long-seam weld type[24]	Double Submerged Arc Weld (DSAW)
Grade[24]	X-52
Outer Diameter[24]	30 inches
Wall thickness[24]	0.375 inches
Coating type	Coal Tar Enamel
Minimum hydrostatic test pressure, at manufacturer (1951)[24]	1,235 psig
Minimum hydrostatic test pressure, in field (1952)[28]	1,125-1,284 psig (about 1,143 psig at rupture elevation)
Minimum hydrostatic retest pressure, in field (1986)[28]	1,265-1,420 psig (about 1,318 psig at rupture elevation)

[24] Fabrication Records

[25] (a) Cathodic Protection Test Station Annual Readings - 3 years

(b) *Impressed current cathodic protection* controls the corrosion of a metal surface (*cathode*) by connecting it to a more easily corroded sacrificial metal (*anode*) and forcing a current of electrons from the anode to the cathode through the use of a rectifier (*impressed current*). In a pipeline application, the protected cathode is the pipeline itself.

[26] (a) Original Depth of Cover

(b) *Depth-of-cover* is the vertical distance measured between the topmost part of the installed pipeline and the grade level directly above it.

[27] 2018 Close Interval Surveys

[28] Hydrostatic Test Records

F.2 Pipeline Operations

At the time of the accident, Lines 10 and 25 were in-service and operating in tandem; Line 15 was not in-service.[29] The flow direction at the time of the accident was north to south.[21] The maximum allowable operating pressure (MAOP) of Line 10 when flowing north-to-south was 936 psig.

Between about 4:00 PM on May 3, 2020 and 4:36 PM on May 4, 2020, the pressure in Line 10 at Owingsville CS monotonically decreased from 727 psig to 655 psig.[30] At the time of the rupture, the pressure in Line 10 at the location of the rupture was about 674 psig. Enbridge was not able to identify an operational reason for the monotonic decrease in pressure in the 24 hours prior to the rupture but indicated that it is consistent with normal system variability.[31]

Enbridge's Supervisory Control and Data Acquisition (SCADA)-based system was operating at the time of the accident.[32] The station operator indicated that there was nothing abnormal in the days prior to the rupture.[33]

There were no remotely controlled valves on the affected pipeline between Owingsville CS and Wheelersburg CS.[34] The isolation valves upstream and downstream of the rupture location are identified in Table 3. The distance between these upstream and downstream valves was about 15 miles. At Owingsville CS, there were also crossover valves (DCO-1, DCO-2, DCO-3, SCO-1, SCO-2, and SCO-3) that allowed gas to cross from one pipeline to another when open.

Table 3. Isolation Valves Upstream and Downstream of Rupture[21]

Line Number	**Upstream Valves** (Muses Mill)		**Downstream Valve** (Owingsville CS)	
	Valve Name	Mile Post	Valve Number	Mile Post
10	10-367	516.82	10-353	502.11
15	15-522	517.32	15-513	502.62
25	25-725	517.32	25-656	502.62

[29] Electrical Control Technician interview
[30] (a) The pressure on Line 10 was measured at Owingsville Station (about 8 miles downstream at MP 502). The pressure on Line 10 at Wheelersburg Station (about 54 miles upstream at MP 564) was 858 psig.
(b) *Monotonically* means varying in such a way that it either never decreases or never increases.
(c) Pressure Data for Lines 10, 15, 25
[31] Enbridge's Explanation of Monotonic Pressure Decrease
[32] PHMSA Incident Reports
[33] Station Operator interview
[34] (a) Director of Gas Control interview
(b) Wheelersburg Station is the next station north of Owingsville Station.

F.3 Integrity Management

Aerial patrol and in-line inspection (ILI) were part of Enbridge's approach to manage the integrity of its pipeline in the area where the accident occurred.[35]

Between December 30, 2015 and May 4, 2020, the segment involved in this accident had been flown for aerial patrol 128 times, most recently on April 22, 2020. Observations were recorded 22 times, including an observation of erosion on the right-of-way near mile post 510 on April 16, 2019. No follow-up actions were noted on the aerial patrol report regarding the erosion observation.[36]

However, in July 2019, some regrading work was performed to address erosion downhill from the failure location. According to Enbridge, the location where the work was performed was about 250-ft from the failure location over Line 25.[37]

Since 2007, ILIs of the affected pipeline in the area where the accident occurred had been completed and reports developed as indicated in Table 4.

Table 4. ILI Runs and Tools Used

ILI Run	ILI Report	Strain Report[38]	Tools Used
April 6, 2007	September 7, 2007	July 19, 2019	Caliper Inertial Measurement Unit
June 5, 2007	September 7, 2007	Not Applicable	Magnetic Flux Leakage-A
October 8, 2009	November 13, 2009	Not Applicable	Magnetic Flux Leakage-A
March 28, 2012	May 29, 2012	Not Applicable	Caliper
March 30, 2012	May 29, 2012	Not Applicable	Magnetic Flux Leakage-A
April 17, 2018	June 14, 2018	July 19, 2019	Magnetic Flux Leakage-A Caliper Inertial Measurement Unit
June 7, 2019	July 24, 2019	September 23, 2019[39]	Caliper Inertial Measurement Unit

Enbridge's contractor, Baker Hughes Company, issued a strain report on July 19, 2019, which indicated a strain magnitude of 0.93% between girth welds 11250 and 11380 and a peak movement of 4.2 feet.[40]

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[35] *In-line inspection* is an inspection method where a highly specialized tool is passed within a pipeline to inspect the pipeline from the inside. ILI uses nondestructive examination techniques to identify, locate, and size various damages and defects, depending on the type of tool.
[36] Air Patrol Records - Jan 2016 to May 2020 - Owingsville Segment
[37] Enbridge Provided Listing of Operations, Maintenance, and Integrity Management Projects (5 years prior to accident)
[38] Line 10 Strain Reports Developed by Baker Hughes for Enbridge
[39] Revised October 21, 2021
[40] (a) This strain comparison report compared 2018 and 2007 IMU data.
(b) Post-Accident Metallurgical Testing and Analysis estimated girth weld strain capacity to be between 1.3% and 2.0% at the MAOP of 936 psig (see Section H.2).
(c) This location includes ruptured girth weld 11330.

Enbridge's contractor, Baker Hughes Company, issued another strain report on September 23, 2019, which indicated a strain magnitude of 1.05% between girth welds 11230 and 11400 and a peak movement of 5.2 feet. The September 23, 2019, report was updated on October 21, 2021, to correct girth weld numbers; the correction indicated that the strain magnitude of 1.05% occurred between girth welds 11220 and 11390.

Both strain reports indicated that the following assumptions were made as part of their analysis:

- The pipeline curvature was calculated along the whole pipeline route. Initial pipe shape was assumed to be straight at manufacture for both sets of the Inertial Measurement Unit (IMU) data.
- Only bending loads were considered; potential additional axial strains due to any other loading mechanisms (thermal elongation/contraction and Poisson's effects in pipeline restrained by anchors or soil interaction; axial forces due to free spanning or buoyancy) were not included.
- The strain analysis did not account for inaccuracies, incompleteness or misclassification of input data.
- Not all defects present on the pipeline were identified, (e.g., narrow axial or circumferential grooves outside the detection and reporting limits of the ILI tool were not considered).

The ILI results for the area near the failed girth weld from 2007 through May 2020 are included in Table 5 through Table 9. The resulting girth weld strain estimates are included in Table 10 through Table 12.

Enbridge evaluated the failure location prior to the accident, through a site assessment (performed in October 2019).[41] Enbridge's site assessment team estimated tensile strain capacity and tensile strain demand based on results from the June 7, 2019 ILI run and determined that urgent action was not required but monitoring and mitigation were recommended.

The site assessment team calculated tensile strain capacity of the unpressurized pipeline, TSC_O, as follows:

$$TSC_0 = \left(CTOD_{GW}^{2.36-1.58\left(\frac{Y}{T}\right)-0.101\left(\frac{l}{wt}\right)\left(\frac{d}{wt}\right)} \right) \left(1 + 16.1 * \left(\frac{Y}{T}\right)^{-4.45} \right) \left(-0.157 + 0.239 \left(\frac{l}{wt}\right)^{-0.241} \left(\frac{d}{wt}\right)^{-0.315} \right)$$

where $CTOD_{GW}$ was the apparent toughness of the girth weld (0.3 mm)
Y was the yield strength (358.5275 MPa)
T was the ultimate tensile strength (455.0542 MPa)
l was the assumed flaw length (50.8 mm)
wt was the wall thickness (9.525 mm)
d was the assumed flaw height (1 mm)[42]

[41] Enbridge's Summary of its Pre-Accident Geohazard Management Program, Site Assessment, and Multidisciplinary Review

[42] Note that the calculation was completed with the metric values, as shown in the main text. The equivalent English units for these variables are: $CTOD_{GW}$ = 0.011811 inches; Y = 52 ksi; T = 66 ksi; l = 2 inches; wt = 0.375 inches; d = 0.0394 inches.

The resulting estimated tensile strain capacity of the unpressurized pipeline was 2.23%. This value was reduced for pressure by dividing it by 1.5, resulting in an estimated tensile strain capacity of the pressurized pipeline of 1.49%. This value was further reduced by multiplying by a safety factor of 0.7. The resulting tensile strain capacity threshold of 1.04%, rounded down to 1%, was then used by Enbridge's site assessment team. Enbridge's site assessment team compared this value to their estimated strain demand at a girth weld of 0.6% to support their decision that urgent action was not needed. Enbridge's site assessment team estimated strain demand at a girth weld by adding the maximum bending strain at a girth weld (see Table 12) to the estimated axial strain at the site (0.15%).[41]

Enbridge indicated that the following assumptions were made as part of the site assessment team's strain demand analysis:

- Initial pipe shape was assumed to be straight at manufacture.
- Average axial strain and maximum bending strain were considered
- The maximum increase in strain demand was 0.13% per year

In early 2020, prior to the accident, Enbridge completed a multidisciplinary review to determine the monitoring and mitigation plan for this location (see Section F.4).

Table 5. 2007 Line 10 ILI Results – CAL + MFL-A[43]

Type	Description	Wheel Count (ft)	Dist To US Weld (ft)	Clock (hh:mm)
BEND	BEND-COLD OVER	40970.1	24.0	
WELD	GIRTH WELD 11310	40986.3	40.2	
MLOS ANOMALY	EXT ML	41012.6	26.3	01:00
BEND	BEND-COLD OVER	41014.5	28.2	
MLOS ANOMALY	EXT ML	41020.9	34.6	06:15
WELD	GIRTH WELD 11320	41026.5	40.2	
BEND	BEND-COLD LEFT	41047.6	21.1	
MLOS ANOMALY	EXT ML	41059.6	33.1	06:00
WELD	GIRTH WELD 11330	41066.7	40.2	
WELD	GIRTH WELD 11340	41081.7	15.0	
DENT ANOMALY	DENT	41100.4	18.8	05:30
WELD	GIRTH WELD 11350	41121.8	40.1	

[43] Line 10 In-Line Inspection Results Since 2007 Excerpt

Table 6. 2009 Line 10 ILI Results – MFL-A[43]

Type	Description	Wheel Count (ft)	Dist To US Weld (ft)	Clock (hh:mm)
BEND	BEND-COLD OVER	40950.8	23.8	
WELD	GIRTH WELD 11310	40966.9	39.9	
MLOS ANOMALY	EXT ML	40993.0	26.1	12:45
BEND	BEND-COLD OVER	40994.8	28.0	
MLOS ANOMALY	EXT ML	41001.2	34.3	06:00
WELD	GIRTH WELD 11320	41006.8	39.9	
BEND	BEND-COLD LEFT	41027.9	21.1	
MLOS ANOMALY	EXT ML	41039.8	33.0	06:00
WELD	GIRTH WELD 11330	41046.9	40.2	
WELD	GIRTH WELD 11340	41062.0	15.0	03:00
DENT ANOMALY	DENT	41080.9	18.9	05:30
WELD	GIRTH WELD 11350	41102.1	40.1	

Table 7. 2012 Line 10 ILI Results – CAL + MFL-A[43]

Type	Description	Wheel Count (ft)	Dist To US Weld (ft)	Clock (hh:mm)
WELD	GIRTH WELD 11310	41046.9	40.2	
MLOS ANOMALY	EXT ML	41073.2	26.3	12:30
MLOS ANOMALY	EXT ML	41081.5	34.6	05:45
MLOS ANOMALY	EXT ML	41084.8	37.8	07:30
WELD	GIRTH WELD 11320	41087.2	40.2	
MLOS ANOMALY	EXT ML	41111.6	24.5	08:15
MLOS ANOMALY	EXT ML	41120.2	33.0	05:45
MLOS ANOMALY	EXT ML	41127.0	39.8	04:45
WELD	GIRTH WELD 11330	41127.3	40.1	
WELD	GIRTH WELD 11340	41142.3	15.0	
WELD	GIRTH WELD 11350	41182.4	40.1	

Table 8. 2018 Line 10 ILI Results – CAL + MFL-A[43]

Type	Description	Wheel Count (ft)	Dist To US Weld (ft)	Clock (hh:mm)
BEND	10 DEG BEND-COLD OVER	40996.4	24.6	
WELD	GIRTH WELD 11310	41011.8	40.0	
MLOS ANOMALY	EXT ML	41037.3	25.4	05:39
MLOS ANOMALY	EXT ML	41038.2	26.4	12:37
MLOS ANOMALY	EXT ML	41046.3	34.5	05:48
WELD	GIRTH WELD 11320	41051.9	40.1	12:00
MLOS ANOMALY	EXT ML	41055.0	3.1	08:11
MLOS ANOMALY	EXT ML	41071.9	20.0	05:57
MLOS ANOMALY	EXT ML	41074.0	22.1	08:03
MLOS ANOMALY	EXT ML	41076.4	24.5	08:17
MLOS ANOMALY	EXT ML	41077.2	25.3	06:10
MLOS ANOMALY	EXT ML	41077.9	25.9	06:33
MLOS ANOMALY	EXT ML	41078.2	26.3	06:11
MLOS ANOMALY	EXT ML	41079.2	27.3	06:18
MLOS ANOMALY	EXT ML	41079.9	27.9	05:28
MLOS ANOMALY	EXT ML	41080.6	28.7	05:55
MLOS ANOMALY	EXT ML	41081.1	29.2	05:17
MLOS ANOMALY	EXT ML	41081.7	29.7	05:55
MLOS ANOMALY	EXT ML	41082.3	30.4	04:39
MLOS ANOMALY	EXT ML	41082.5	30.6	06:22
DwSW ANOMALY	DENT	41084.0	32.0	12:00
MLOS ANOMALY	EXT ML	41084.3	32.4	05:15
MLOS ANOMALY	EXT ML	41084.9	33.0	05:49
WELD	GIRTH WELD 11330	41092.0	40.1	
WELD	GIRTH WELD 11340	41107.1	15.0	
WELD	GIRTH WELD 11350	41147.1	40.0	

Table 9. 2019 Line 10 ILI Results – CAL[43]

Type	Description	Wheel Count (ft)	Dist To US Weld (ft)
WELD	GIRTH WELD 11350	286698.206	39.09
WELD	GIRTH WELD 11340	286738.273	40.07
WELD	GIRTH WELD 11330	286753.272	15.00
BEND	52.8D 5.5 DEG LEFT TURN SAG BEND	286765.547	12.27
WELD	GIRTH WELD 11320	286793.495	40.22
BEND	40.6D 6.3 DEG RIGHT TURN OVER BEND	286823.429	29.93
WELD	GIRTH WELD 11310	286833.786	40.29
BEND	36.4D 7.7 DEG OVER BEND	286848.069	14.28

Table 10. 2018 Girth Weld Strain Estimates[38]

Girth Weld	Strain Magnitude (%)
11300	0.071
11310	0.436
11320	0.243
11330	0.353
11340	0.112
11350	0.116
11360[44]	0.181

Table 11. 2019 Girth Weld Strain Estimates – Report Issue 1 (September 23, 2019)[38]

Girth Weld	Abs Dist (ft)	Strain Magnitude	Horizontal Strain	Vertical Strain
11310	40949.5	0.057	0.019	0.054
11320	40989.7	0.414	-0.404	-0.091
11330	41030.0	0.208	0.206	0.032
11340	41070.2	0.375	0.186	0.326
11350	41085.2	0.108	0.034	0.102

Table 12. 2019 Girth Weld Strain Estimates – Report Issue 2 (October 21, 2021)[38]

Girth Weld	Strain Magnitude (%)
11300	0.055
11310	0.406
11320	0.208
11330	0.383
11340[44]	0.114
11350	0.137
11360	0.182

[44] (a) The strain value can be affected by tool ride over the girth weld or an adjacent construction bend / fitting. Where this is the case, the girth weld strain is not considered in the selection of the maximum girth weld strain detailed below.
(b) According to Enbridge, it corrects for the effect of tool ride over in its analysis.

F.4 Geohazard Management Program

Enbridge was in the process of developing a program, but did not have specific procedures to manage geohazard threats in non-High Consequence Areas at the time of the accident.[45] However, several existing Enbridge Standard Operating Procedures (SOPs) included elements related to geohazard threats in non-HCAs, including:[46]

- SOP 1-6010, *Pipeline Patrol and Leakage Survey Frequency Criteria*. This procedure, in part, required aerial patrols to be performed on a monthly basis (if weather and aircraft maintenance allowed), not less than once per calendar year at the accident location. The aerial patrols were to look for indications of seismic activity, soil slides, subsidence, and other factors.
- SOP 1-6040, *Aerial Pipeline Patrol.* This procedure required, in part, that aerial patrol pilots kept a log of their observations, including the general conditions of the right-of-way, indications of water erosion, soil slippage, or landslide areas, indications of gas leakage (e.g., discolored or wilted vegetation), and construction activity.
- SOP 1-6060, *Mining Subsidence and Soil Slippage*. This procedure required, in part, that protective measures be performed when excessive deformations or significant increases of pipe stress were suspected. Protective measures included relocating the pipeline to a more stable area, removing sliding soil, stabilizing the land, and excavating a trench parallel to the pipeline to relieve lateral soil pressure.
- SOP 1-5010, *Right-of-Way Maintenance.* This procedure required, in part, erosion control measures, including repairing erosion sites as soon as practical after discovery and restoring exposed or shallow pipelines.

In 2018, Enbridge started their Geohazard Management Program to identify and assess areas of increased geohazard risk. Enbridge contracted BGC Engineering USA, Inc. (BGC) to perform an initial geohazard screening of the Enbridge natural gas transmission pipeline system which included a desktop review of publicly available LiDAR, aerial imagery, existing landslide databases, and relevant geologic maps.[41,46]

Enbridge and BGC relied on landslide susceptibility maps, published state-specific landslide inventories, and SME review of publicly available LiDAR along the right-of-way to identify the 2018 desktop inventory of geohazard sites.[47] Ground inspections were scheduled for priority sites that were identified in desktop studies. According to Enbridge, approximately 1,100 ground assessments were completed in 2019, by a geohazard expert to look for evidence to help explain the strain features (if present) and characterize the ground movement activity level and pipeline vulnerability to ground movement.[46] Sites with elevated activity levels or elevated strains were reviewed with Enbridge as part of their multi-disciplinary review process. Enbridge considered the strain signature, site observations, and

[45] (a) Threat Response Guideline (TRG) 490, *Weather-Related and Outside Forces*, only applied to HCAs.
(b) Enbridge had submitted its draft program procedures to PHMSA for review on October 15, 2019 but the procedures had not been finalized prior to the accident.

[46] Enbridge Procedures in Effect Prior to Accident (Excerpts)

[47] In 2019, following the Summerfield, OH incident, the results from IMU bending strain reports were incorporated into the evaluation process.

estimated strain demand and capacity to provide a recommendation for the next monitoring or mitigation action and the deadline by which it was to be accomplished.[48]

The area where Line 10 ruptured on May 4, 2020, was first identified as a potential geohazard on October 9, 2018, as part of the initial geohazard screening. The site received a high priority rating with a ground inspection planned to be completed within one year from the date of identification.

On June 27, 2019, Baker Hughes (the ILI vendor) issued a priority notification to Enbridge for an about 0.93% strain feature identified while processing the 2018 IMU data.[49] Upon review of the 2018 IMU report, BGC categorized the site as a high priority site and completed the ground inspection on July 8, 2019. BGC measured about 4.3 feet of downslope deflection on Line 10 which they indicated correlated with the 2018 IMU data. Scarps were identified at upslope ends of deflections.[50]

Based on the field findings, Enbridge completed a strain demand assessment on July 15, 2019, using the field-measured deflections. The maximum strain at a girth weld was estimated to be 0.85% (GW 11320). Based on the strain assessment, continued monitoring and future stress relief was recommended. Baker Hughes submitted the completed report on the June 2019 IMU run to Enbridge on September 23, 2019, which indicated about 5 feet deflection on Line 10 and 1.05% bending strain. Enbridge completed an updated strain demand assessment on October 30, 2019 and confirmed that continued monitoring and mitigation was required along with future stress relief. BGC developed an interim report (November 15, 2019) and program proposal (December 6, 2019). According to Enbridge, the geohazard team was aware that work had been completed on the right-of-way in June or July 2019 but was not aware of the exact nature or magnitude of the work done.[41]

A multidisciplinary review meeting with Enbridge and BGC was held on February 18, 2020. Based on estimated strain demand and other considerations, the multidisciplinary team determined no immediate actions were needed. The multidisciplinary team did plan to install strain gages and drainage. According to Enbridge, they also planned to complete additional monitoring, mitigation, and future stress relief in the Summer 2020. Enbridge requested BGC prepare a scope of work for additional monitoring including strain gauge installation and X-ray testing of girth welds during strain gauge installation, noting that the pipe would be cut-out if damage was found. On March 24, 2020, BGC submitted a proposal for this work. The accident occurred before the monitoring and mitigation activities were completed.

[48] Throughout 2019, Enbridge collected additional data for their overall Geohazard Program, including helicopter flyovers and ILI tool runs equipped with IMU. From this data, Enbridge selected 27 sites requiring immediate remediation in 2019. An additional 27 sites were selected for remediation in 2020, including the accident site.

[49] This resulted from the July 19, 2019 strain report discussed in Section F.3.

[50] A *scarp* is a steep surface of exposed material produced by differential movement. (https://pubs.usgs.gov/circ/1325/pdf/C1325_508.pdf)

F.5 Emergency Response Procedures

Enbridge required an immediate response by personnel when there was either an extreme pressure reduction on a line or notification of an emergency. Enbridge's procedures indicated that Gas Control personnel monitor and control line pressures, control product flow rate, operate remote controlled valves and operate compressor stations. Should a leak occur, Gas Control was directed to dispatch field personnel to make an assessment and begin response efforts.[14]

Enbridge's *Gas Transmission and Midstream Emergency Response Plan* states that it provides guidance to company personnel with immediate procedures to take in the event of an emergency response incident originating at any Enbridge area of gas operations. The core plan elements include: detection of a release, incident response, notification procedures, response management system, site security and control, documentation, demobilization, response termination, and investigation of failures.[14]

According to the plan, Enbridge's safety systems and practices are designed to alert operators with alarms in the event of a release. The plan indicates that station operators and gas controllers are trained to respond to the various system alarms in order to identify and control releases immediately.[14]

Enbridge procedures described initial response efforts that included: securing the source, calling for medical assistance, shutting off ignition sources, coordinating rescue and medical response actions, identifying hazards to life safety, conducting air monitoring, and following notification procedures.[14]

F.6 Regulatory Oversight of the Pipeline System

Federal pipeline safety regulations are found in 49 *CFR* Parts 190-199.

PHMSA regulations in 49 *CFR* Part 191, *Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports,* require operators to provide immediate notice to the National Response Center (NRC) following an incident if it meets specific criteria. If such an event occurs, the operator is also required to submit a PHMSA Incident Report as soon as practicable but not more than 30 days after detecting the incident. Supplemental reports are required if additional information is obtained after the report is submitted.

PHMSA regulations in 49 CFR Part 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards,* include several requirements that are applicable to the affected pipeline, such as:

- [Subpart M – Maintenance] 49 CFR 192.703(b). Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
- [Subpart M – Maintenance] 49 CFR 192.705. Gas transmission pipeline operators shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation and the frequency of patrols must be based upon the size of the line, operating pressures, class locations, terrain, seasonal weather conditions, and other relevant factors.
- [Subpart L – Operations] 49 CFR 192.613(a). Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.
- [Subpart L – Operations] 49 CFR 192.613(b). If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the MAOP in accordance with 49 CFR 192.619(a) and (b).

However, PHMSA regulations in 49 CFR Part 192, Subpart O, *Gas Transmission Pipeline Integrity Management,* do not apply to the affected pipeline in the location where the accident occurred. Additionally, certain requirements of current PHMSA regulations are not applicable to the affected pipeline because the pipeline predated the requirement. For example, API Standard 1104, *Welding of Pipelines and Related Facilities*, is incorporated by reference in the current regulations, but does not apply to the pipeline involved in the accident because it predates the requirement. Similarly, the requirements of 49 CFR Part 192, Subpart D, *Design of Pipeline Components* (including 192.103) and Subpart G, *General Construction Requirements for Transmission Lines and Mains* (including 192.317(a)) are not applicable because the affected pipeline predates these design and construction requirements.[51]

On May 2, 2019, PHMSA issued an advisory bulletin titled, “Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards.”[52] PHMSA’s advisory bulletin highlights seven accidents and incidents that occurred between 2016 and 2019. One of the highlighted incidents involved a girth weld rupture on a different operator’s system that was attributed to earth movement and occurred near Summerfield, Ohio on January 31, 2018 (about 5 miles north of the January 21, 2019, rupture on Line 10 discussed in Section F.7).

F.7 Pipeline System Performance History

Previous incidents and Safety Related Conditions (SRCs) that were attributed to earth movement or incomplete penetration of girth welds on TET included:[53,54,55,56]

- **Gaysport, Ohio (July 3, 1990).** The operator reported that landslide movement caused the 1943 vintage 24-inch steel pipeline to fail. The operator indicated that the pipeline was located in a major landslide area that encompassed most of the pipeline right-of-way. Movement of the landslide was described as unpredictable and able to be triggered by rainfall, changes to the terrain, or natural causes.
- **Beallsville, Ohio (May 6, 1998).** The operator reported that forces associated with soil slippage along the hillside caused the 1952 vintage 30-inch steel pipeline to rupture at a girth weld.
- **Trousdale County, TN (December 8, 2015).** The operator reported that a slow natural gas leak occurred on 30-inch Line 10 (MP 307.70) resulting from a crack in a girth weld caused by a lack of penetration weld defect that was subjected to secondary loading.
- **Summerfield, OH (January 21, 2019).** Line 10 failed at a girth weld, resulting in two injuries and the destruction of four buildings. The accident was determined by PHMSA to be caused by ground movement that overstressed a girth weld to failure. An internal investigation by Enbridge found that the girth weld failed from ductile overload from a longitudinal tensile or bending force that exceeded the load carrying

[51] (a) 49 CFR 192.103 requires, “Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.”
(b) 49 CFR 192.317(a) requires, in part, that “The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.”

[52] https://www.regulations.gov/document/PHMSA-2019-0087-0001

[53] https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files (PHMSA Reports 19900135, 19980094, 20160001)

[54] Summary of Enbridge's Findings Following its Investigation of the Summerfield Ohio Incident

[55] https://www.phmsa.dot.gov/data-and-statistics/pipeline/leading-indicators-srcr-and-im-notifications (Accessed October 18, 2021)

[56] https://primis.phmsa.dot.gov/comm/reports/enforce/documents/220191002H/220191002H_Second%20Amended%20Corrective%20Action%20Order_06012020.pdf

capacity of the weld. Enbridge's investigation team developed 21 recommendations to reduce recurrence of similar accidents on their system, including the following:

- Perform a baseline strain inline inspection (or reinspection of existing strain data) of all TET segments within the Appalachians and other geotechnically active areas to identify accumulations of concentrated strain
- Develop and provide training to Area Operations Pipeliners and Regional Operations Integrity experts on the recognition, risk, and management of geohazards
- Revise or replace the existing procedures with a comprehensive geohazard management program applying to all Enbridge gas transmission pipeline assets
- Develop a quasi-independent verification process that assesses whether all integrity hazards will be reasonably and prudently addressed through the integrity risk controls in the integrity management program

ILI tools equipped with IMUs found the section of Line 10 near the Summerfield, Ohio rupture moved 6 feet between the date of original construction and 2012 (60 years) and 2-3 feet further from 2012 to 2019 (7 years). The increased rate of movement was determined to be caused by "record rainfall amounts in the 12 months preceding the rupture" with further destabilization by site development. Post-rupture, two wrinkles at the fixed end and ovality deformation on the free end were observed which were not identified during the 2012 ILI runs.

Metallurgical testing from the Summerfield, Ohio rupture performed by DNV GL USA, Inc. (DNV) found two incomplete penetration flaws within the failed weld of "2.2 - 2.3 inches in length" resulting in a "a reduced load carrying capacity of 0.345% to 1.3%." DNV determined these flaws were "negligible when compared to other variables included in the calculations." Tensile properties, toughness properties, and chemical composition were all found to be within standard ranges for the age of weld and API 5L grade X-52 requirements, as of the time of construction.

- **Pennsylvania and West Virginia SRC Report (March 13, 2020).** On March 25, 2020, TETLP submitted SRC Report 20-178572 to PHMSA due to land movement causing a deflection of 7.1 feet along a length of about 350 feet of the pipeline. The location was between MP 721.35 and MP 722.90 on Line 25.

G. Post-Accident Response

The pipeline rupture resulted in a fire which burned vegetation over approximately 5 acres of heavily forested land. The rupture occurred at a girth weld with no ejection of pipe. No structures were damaged.

G.1 Operator Response

A timeline of the operator's response to this accident is included in Appendix A. Below is a summary of those actions.

Gas Controller A indicated that he received a call attendant alarm from Owingsville CS at 4:39 p.m, and confirmed the compressors were still running. At the time that the call attendant alarms was received, he was discussing an issue unrelated to the rupture with an external caller. While he was on this phone call, his coworkers at Gas Control began receiving calls related to the rupture. Gas Control's initial notification of the rupture was from a member of the public at 4:40 p.m. Initial notification of the rupture to field personnel was also at 4:40 p.m from a technician's personal friend at 9-1-1 dispatch.[57] In the minutes that followed, the Owingsville Area Supervisor dispatched field personnel to the Muses Mill valve site and to Owingsville CS to begin isolating the affected segment.

The three upstream isolation valves (at Muses Mill) were closed at 5:23 PM. At 5:26 PM, the valves at Owingsville CS were closed. At 5:29 PM, Gas Control confirmed that the affected valve section was isolated. At 5:40 PM, Gas Control confirmed that the ruptured segment was isolated. At 9:05 PM, field personnel began blowing down the isolated sections; blowdown was complete at 9:20 PM. Field personnel performed a leak survey at the accident site and permitted Forest Service to access area to put out small fires.

[57] No rate-of-change alarms were observed; Enbridge does not employ the use of rate-of-change alarms on the suction side of this compressor station. Enbridge indicated that it does not employ the use of rate-of-change alarms on the suction side of the compressor station due to concerns of false alarms. (Interview of the Director of Gas Control)

Figure 4. Accident Site Post-Rupture, Taken 5/5/2020 (Courtesy of PHMSA)

G.2 Drug and Alcohol Testing

All six Gas Controllers who were working at the time of the accident were screened for drugs and alcohol; all drug and alcohol screens were negative.

G.3 Incident Reporting

On May 4, 2020 at 5:40 PM, Enbridge submitted National Response Center (NRC) Incident Report 1276640. The report indicated that a natural gas transmission pipeline ruptured due to unknown reasons and resulted in a fire. Enbridge noted that crews had been dispatched for investigation.

On May 6, 2020 at 4:24 PM, Enbridge submitted NRC Incident Report 1276770. This report provided an estimated release quantity of 51,676 mcf and indicated that the release had been secured, the fire had been extinguished, and there were no reported injuries or fatalities.

On June 2, 2020, Enbridge submitted PHMSA Incident Report 20200057-33836. The report indicated that this accident resulted in an unintentional release of about 51,684 mcf and an intentional, controlled release of about 96,400 mcf. The incident report further indicated that there were no fatalities or injuries, but there was a rupture, explosion, ignition, and evacuation of 2 members of the general public. Enbridge estimated the depth-of-cover to be 54 inches and indicated that the potential impact radius was 633 feet. Enbridge also estimated the cost of damage to public and non-operator private property ($700,000), operator's property damage and repairs ($10,000,000), and emergency response ($1,000,000).[58]

On November 23, 2021, Enbridge submitted PHMSA Incident Report 20200057-36037. The report updated the estimated pressure at the point and time of the rupture to be 674 psig and the apparent cause to "Other Natural Force Damage."[58]

H. Post-Accident Tests and Research

Following the accident, BGC was contracted to provide a geotechnical causation assessment. DNV was contracted to perform metallurgical testing and analysis. Stress Engineering Services, Inc. (SES) was contracted to evaluate the tensile strain capacity of Line 10 which was used by DNV to complete their assessment.

H.1 Geotechnical Causation Assessment

BGC performed field-based and desktop studies, concluding that Line 10 was installed within a landslide feature that was accelerating, causing a rapid increase in pipe strain in the months preceding the rupture. BGC indicated that the large acceleration in the 6 months prior to this accident was likely driven by a combination of high levels of precipitation, pre-existing cracks, additional ground water conveyance along the pipeline trenches, and loading associated with grading activities. The work BGC completed is summarized below.[4]

H.1.1 Site Mapping

BGC mapped the landslide at the accident site by documenting and surveying ground cracks, scarps and toe bulges on and downslope of the pipeline corridor on May 7-9, 2020.[59] The approximate accident and landslide locations are shown in Figure 5 and Figure 6, respectively. A cross-section of the three pipelines near the rupture location is shown in Figure 7.

[58] PHMSA Incident Reports
[59] The *toe* is the lower, usually curved margin of the displaced material of the landslide, furthest from the main scarp. The *main scarp* is located at the upper edge of the landslide.

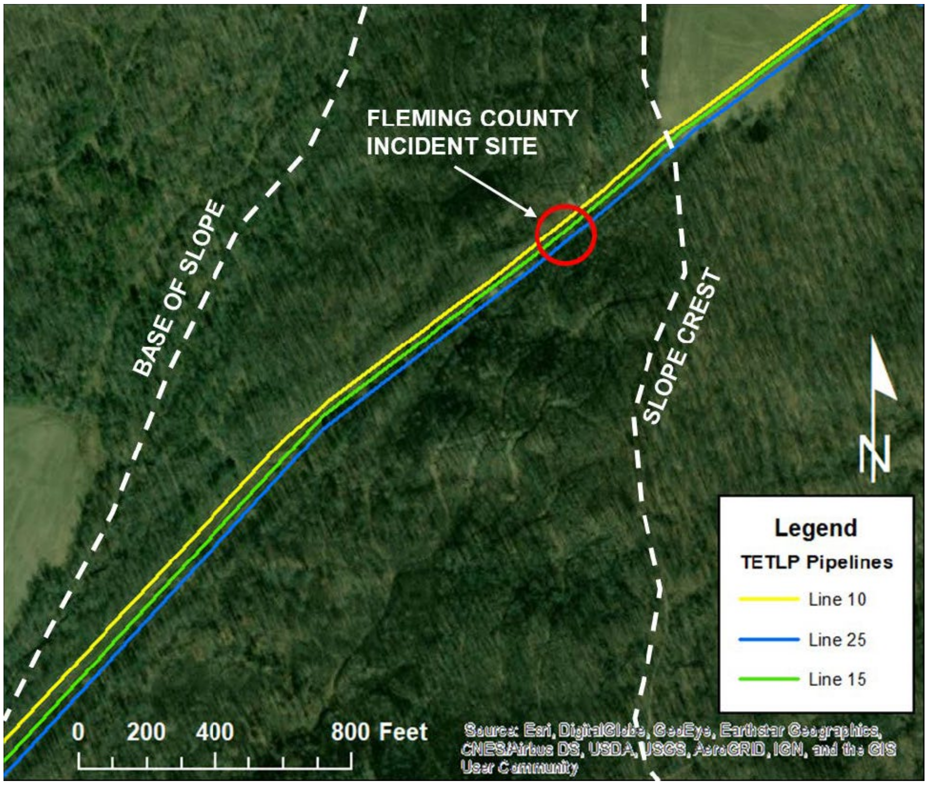

Figure 5. Accident Location (Identified as "Fleming County Incident Site")[4]

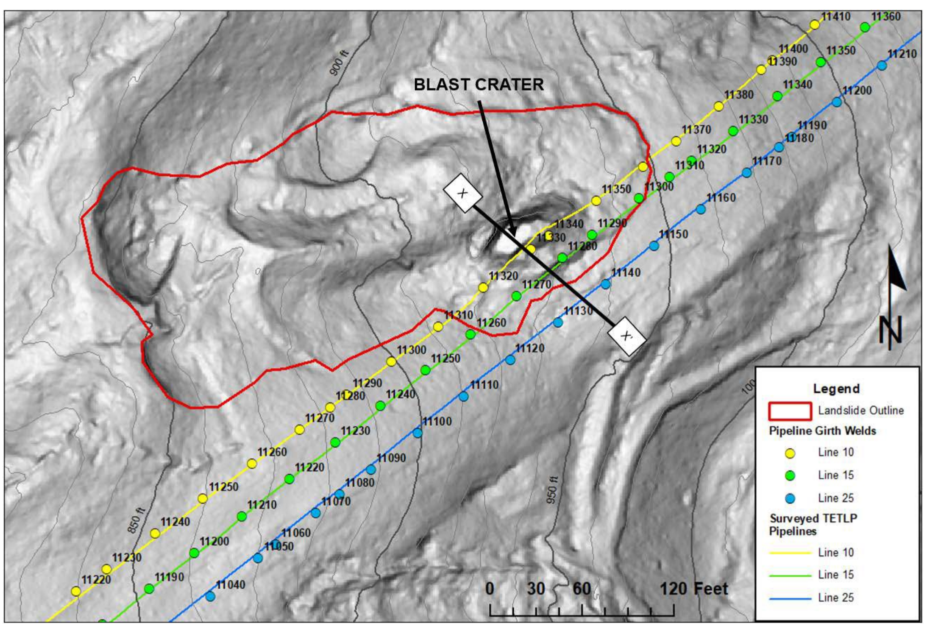

Figure 6. BGC Defined Landslide Location Relative to Lines 10, 15, and 25[4]

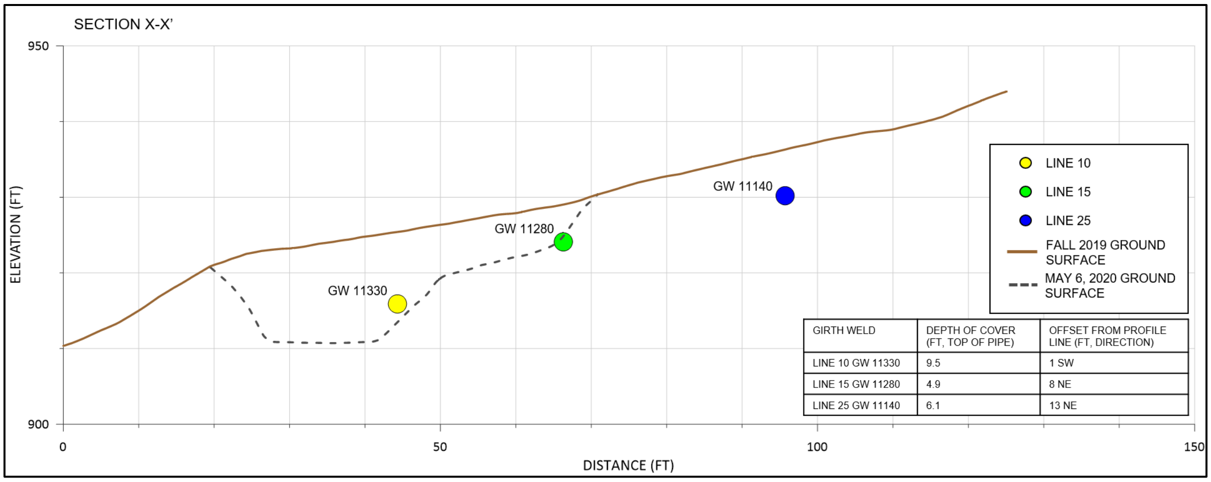

Figure 7. BGC Estimated Cross-Section of Line 10, 15, and 25, Corresponds to Figure 6[4]

H.1.2 Characterization of Geological Conditions Along Pipeline Right-of-Way

Based in part on a literature review, BGC indicated that the area around the accident site was highly susceptible to landslides. BGC determined that Line 10 was situated in colluvium (past landslide deposits) for a length of approximately 165 ft, between 10 ft upslope of GW 11310 to 5 ft upslope of GW 11360, and in weathered bedrock for an additional 80 ft upslope, just upslope of GW 11380. Based on shape accel array (SAA) data obtained between July 23 and September 4, 2020, BGC determined that the slip surface of the landslide was confined to the colluvium and did not extend into the underlying bedrock.[60]

H.1.3 Ground Movement

BGC assessed pre- and post-accident data to estimate the lateral displacement of the pipeline at the accident site. This lateral displacement, commonly referred to as out-of-straight (OOS), was derived from IMU data, ground staking, lidar scans, and/or survey data. BGC found that the OOS for Line 25 was of small magnitude and more consistent with OOS related to construction rather than downslope movement.

For Lines 10 and 15, BGC used the OOS measurement and the orientation of the landslide to estimate the minimum ground movement that had impacted the pipelines. The results, shown in Table 13, are considered minimums because they assume that the landslides' lateral movement will displace the pipeline laterally by the same amount. BGC calculated that the average minimum ground movement on Line 10 was less than one inch per year between 1952 and June 2007; 10-11 inches per year between June 2007 and June 2019; and 10.1 feet per year between June 2019 and May 2020 (post-accident). BGC noted that a less significant increasing average minimum ground movement was observed on Line 15, indicating that Line 10 was in a more vulnerable position.

[60] *SAAs* use micro electrical mechanical sensors to measure real time displacements.

BGC continued monitoring landslide movement following the accident using 2-foot lengths of rebar that were driven into the ground. Of the rebar locations that were placed in the landslide mass for at least one month, the observed displacement ranged from about 1-2 feet per month on average for the first two months. BGC observed that the movement occurred in distinct episodes with the greatest movement following a 4-inch precipitation event.

BGC also reviewed airborne lidar scanning (ALS) data, aerial imagery, historic rainfall, and past construction activities, documenting those factors that may have contributed to the landslide movement.

ALS data was collected in 2017 (no month provided), November 2019, and May 6, 2020. BGC found that local landslides had similar amounts of ground movement between 2017 and 2019, but the landslide at the accident site was that only landslide with appreciable movement between November 2019 and May 6, 2020.

BGC also acquired and reviewed aerial imagery that had been taken of the accident site between 1959 and 2018. Based on this review, BGC found that:

- Bare soil – indicative of erosion – was observed as far back as September 1959 and as recently as October 2018.
- Recent construction, which can cause or worsen slope instability, was evident in imagery taken in October 1965, March 1988, and July 2012.
- Timber harvesting, which can initiate or worsen slope instability, was evident in imagery taken between July 2006 and July 2010.

BGC considered historic rainfall as a potential contributor to ground movement, noting that landslides within colluvium are often initiated during periods of above average precipitation. BGC noted that the decade between 2010 and 2020 had 15% more precipitation than the long-term average. Within this decade, BGC noted that 2018 and 2019 had 58% and 33% more rainfall than the long-term average, respectively. BGC found that precipitation and seepage played a key role in driving landslide movement before the accident. BGC observed that the dominant source of seepage was fracture shale beds. BGC also observed that groundwater preferentially flowed along the backfilled pipeline trenches downslope into the active landslide mass.

BGC obtained locations of past documented construction activities along the TET corridor near the accident site from Enbridge. BGC noted that the pipeline construction activities that are of the greatest relevance for slope stability are grading, disruption or alteration of surface or subsurface drainage and disturbances related to construction equipment traffic. The only past activity BGC obtained related to these factors was erosion repair work that was performed in June and July 2019. BGC indicated that their staff was onsite for a geohazard inspection during this restoration work and noted that erosion control matting covered the accident site. During this inspection, BGC observed that cracks on the pipeline corridor were infilled but cracks off the pipeline corridor were not. BGC indicated that these remaining cracks would intercept surface water flows, conveying the water directly into the slide mass, driving further movement.

BGC estimated the depth-of-cover at the failed girth weld on line 10 and the nearest upstream girth welds on lines 15 and 25 based on the grade prior to rupture (extracted from LiDAR data from November 2019). As shown in Table 14, Line 10 had a greater depth-of-cover than either Line 15 or 25. BGC suggested that grading activities over the life of the pipelines may have incrementally added to the depth-of-cover for Line 10.

Table 13. Estimated Lateral Displacement and Minimum Equivalent Ground Movement

	Estimated Out-of-Straight (ft)		***Minimum Equivalent Ground Movement (ft)***	
Date	**Line 10**	**Line 15**	**Line 10**	**Line 15**
June 2007	1.3		3.3	
April 2011		1.4		3.6
May 2017		2.6		6.7
April 2018	4.7		12	
May 2019		2.9		7.4
June 2019	5.1		13.1	
July 2019 (stake position)	5.8		No Estimate[61]	
October 2019		3		7.7
May 2020 (post-rupture)[62]	8.7	3.75	22.3	9.6

Table 14. Depth-of-Cover Near Rupture Location Prior to Accident (Estimated by BGC)[4]

Girth Weld	**Depth-of-Cover (ft)**
Line 10, GW 11330	9.5
Line 15, GW 11280	4.9
Line 25, GW 11140	6.1

[61] BGC did not estimate the minimum equivalent ground movement based on July 2019 stake positions due to the level of error within the ground staking measurements (+/- 1 foot) completed during the July 2019 ground inspection. BGC noted that for the short time period between the June 2019 IMU and July 2019 field OOS measurements, the error bounds of the staking could provide a broad range of potential ground movement rates.

[62] Line 10 OOS measurements estimated based on May 6, 2020, 3D lidar scan and SGC survey centerline (May 7-8, 2020). The lidar scan was completed prior to the use of heavy equipment and immediate construction activities on the site. BGC noted that actual OOS immediately prior to the accident would have been less because caving of the blast crater further deflected Line 10. Line 10 OOS measurements were described by BGC as "rudimentary" because unstable ground conditions caused by the accident limited direct access.

Table 15. IMU-derived Bending Strain on Pipeline[4]

IMU Run Date	Total Bending Strain	
	Maximum Calculated on Pipe Body	GW 11330
June 2007	0.352%	0.165%
April 2018	0.926%	0.353%
June 2019	1.050%	0.364%

H.2 Metallurgical Testing and Analysis

Based on the work completed by DNV and SES, DNV concluded that the girth weld failure was the result of ductile overload from forces induced by land movement that exceeded the tensile strain capacity of the weld.

Two incomplete penetration and lack of root fusion defects were identified on the fracture surface of the failed girth weld.[63] One defect was about 7 inches in length and 0.130 inches in depth. The other defect was about 4.9 inches in length and 0.100 inches in depth. These defects were not modeled in the finite element analysis performed by DNV which resulted in the tensile strain demand estimates indicated in Table 16. The estimated tensile strain demand was lower than it would have been if these defects had been included.

SES evaluated exemplar girth welds, fabricated and tested curved wide plate specimens, developed finite element models of selected curved wide plate specimens, developed a finite element model of the full circumferential pipe with defects, and estimated the tensile strain capacity.[64] The exemplar girth welds extracted from Line 10 following the rupture included GW 11260, 11270, 11280, 11290, 11300, 11310, 11320, 11330 (ruptured), 11340, 11350, 11360, 11370, and 11380.[65] These girth welds had been fabricated at the same time as the ruptured girth weld and spanned a distance of approximately 400 feet. Failure strains for the curved wide plate samples are shown in Table 17. The full circumferential pipe model explicitly included the flaws found in the curved wide plate specimen with the lowest strain to failure (sample 11310-A) but did not contain any weld flaws beyond the 4-inch curved wide plate region.[66] The full circumferential pipe model was used by SES to estimate the load versus tensile strain relationship of the full pipe. SES estimated the crack driving force

[63] (a*) Incomplete penetration defects* occur when the weld root is not completely filled (both sides of the weld root are not fused).
(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.
[64] Three specimens with known defects (11280B, 11310A, and 11380A) were modeled. The defect in Specimen 11280B was induced (2-inch long by 0.196-inch deep electronic discharge machining notch) prior to testing.
[65] The locations of curved wide plate samples were selected to include defects discovered through nondestructive evaluation.
[66] The material properties used in the finite element model were based on flawed samples.

($CTOD_F$) to establish tensile strain capacity as indicated in Table 16.[67] Inclusion of defects reduced the tensile strain capacity compared to girth welds without defects or imperfections; more severe defects would reduce strain capacity further. The tensile strain capacity estimates did not account for prior deformation (if any).[68]

Additional information pertaining to the metallurgical testing and analysis is contained in the Materials Laboratory Factual Report 21-085.

Table 16. Tensile Strain Demand and Capacity Estimate by DNV and SES[69]

<table>
<tr><th>Year</th><th>Tensile Strain Demand
(DNV, Pipe without Defects)</th><th>Tensile Strain Capacity
(SES, Pipe with Defects)</th></tr>
<tr><td>2007</td><td>0.7% at 858 psig</td><td rowspan="3">1.3% - 2.0% at 936 psig
2.4% - 3.6% at 0 psig</td></tr>
<tr><td>2018</td><td>1.8% at 858 psig</td></tr>
<tr><td>2020</td><td>3.0% at 858 psig</td></tr>
</table>

[67] The $CTOD_F$ was calculated from the deformed crack surface profile along the edge of the flaw for the three selected specimens (11280B, 11310A, and 11380A).

[68] Samples 11280B, 11310A, and 11380A, used to estimate tensile strain capacity, were about 174, 81, and 162 feet from the failure location, respectively.

[69] Metallurgical Analysis of Failure of Girth Weld by DNV GL USA, Inc.

Table 17. Failure Strains for Curved Wide Plate Samples[69]

Non-EDM Notched		EDM Notched	
Sample	**Failure Strain in Constant Strain Region (%)**	**Sample**	**Failure Strain in Constant Strain Region (%)**
11260-A	7.65	11270-A	8.15
11260-B	7.14	11270-B	3.56
11260-C	5.14	11270-D	8.34
11260-D	9.75	11270-E	8.22
11290-A	16.22	11280-A	11.16
11290-B	6.46	11280-B	4.71
11290-C	14.44	11280-D	3.22
11290-D	8.42	11280-E	1.68
11300-A	9.89		
11300-B	9.69		
11300-C	16.22		
11300-D	15.80		
11310-A	1.41		
11310-B	15.62		
11310-C	15.79		
11310-D	2.24		
11360-A	9.37		
11360-B	11.33		
11360-C	10.35		
11360-D	8.52		
11370-A	7.75		
11370-B	8.02		
11370-C	5.45		
11370-D	2.64		
11380-A	4.41		
11380-B	4.19		
11380-C	9.94		
11380-D	3.56		

I. Post-Accident Actions

In response to this accident, PHMSA took regulatory action and Enbridge implemented safety improvements. These actions are summarized below.

I.1 PHMSA

On June 1, 2020, PHMSA issued an amended Corrective Action Order (CAO) which required corrective actions be taken with respect to Lines 10, 15 and 25 for failures on August 1, 2019, near Danville, Kentucky, and May 4, 2020, near Hillsboro, Kentucky.[70]

The CAO required the following corrective actions in response to the Hillsboro, Kentucky accident:

- The isolated sections of Lines 10 and 15 must not be operated without authorization from PHMSA.
- The remainder of the *affected segment* must operate at a reduced pressure until PHMSA provides written approval for an increase.[71]
- Prior to resuming operation of any part of the *failure 2 isolated segment*, TETLP must develop and submit a written restart plan to PHMSA.[72] Upon resuming operation, this segment must operate at a reduced pressure until PHMSA provides written approval for an increase.
- TETLP must perform an aerial or ground instrumented leakage survey of the *affected segment*, investigate all leak indications, and remedy all leaks discovered.[71]
- Records Verification
- Review of Prior ILI Results
- Mechanical and Metallurgical Testing
- Root Cause Failure Analysis
- Emergency Response Plan and Training Review.
- Public Awareness Program Review
- Remedial Work Plan
- CAO Documentation Report

[70] The August 1, 2019 accident that occurred near Danville, Kentucky is currently under investigation by the NTSB. Additional information can be found in the public docket for NTSB accident investigation (accident number PLD19FR002) by accessing the NTSB Accident Dockets Link at www ntsb.gov.

[71] *Affected segment* means the three parallel bi-directional pipelines operated by TET located within the common right-of-way that transports natural gas from Kosciusko, Mississippi to Union Township, Pennsylvania.

[72] *Failure 2 isolated segment* means the portion of the affected segment that was shut-in after the rupture on May 4, 2020, by closing mainline valves upstream and downstream of the rupture and that remains shut-in as of May 30, 2020 for Lines 10 and 15.

I.2 Enbridge[73]

Following the accident, Enbridge initiated, continued, or completed several safety improvements. Documentation of some several new procedures were provided to NTSB investigators, including:

- PI-05.701 Bending Strain Reporting work instruction which defines the ILI vendor reporting requirements for consistent reporting for all vendors across all company pipelines;
- PI-05.702 Inertial Measurement Unit Acceptance Work Instruction to confirm that the data collected through IMU tools is suitable for use for accurate pipe centerline location, accurate anomaly location, processing for bending strain analysis, and analyzing for pipeline movement when comparing two or more individual IMU runs;
- PI-05.704 Assessing Excavations for Geohazards Work Instruction for assessing planned excavations to evaluate if those excavation will be conducted in areas subject to geohazards and if so, ensure that measures are identified to mitigate potential hazards;
- PI-05.718 Geohazard Multi-Disciplinary Review Work Instruction to ensure consistent review and decision-making when evaluating geohazard sites.
- PI-05.720 Tensile Strain Capacity (TSC) Assessment Work Instruction that implements a standardized approach to establish the TSC of a girth weld. Assumed defects are to be sized based on actual X-ray records or conservatively estimated based on historical records and subject matter expert judgment.
- PI-05.721 Unstable Slope and Subsidence Classification and Response Work Instruction that provides guidance for applying the Unstable Slope and Subsidence Classification Matrix and determining the appropriate response actions and timing; and

Enbridge told the NTSB IIC that the new procedures:

- result in a reduced tensile strain capacity threshold of 0.5% on Line 10 in the area where the accident occurred.
- would result in a high priority response action (R7) for any landslide that crosses the centerline of the pipeline or crosscuts the right-of-way, if the estimated tensile strain demand exceeds the tensile strain capacity threshold.
- require the following actions whenever an R7 classification is determined:
    - site visit within 48 hours
    - site-specific monitoring plan within 30 days of classification
    - immediate pressure restriction or shutdown
    - drainage installation if appropriate for site-specific conditions

Additionally, Enbridge acknowledged that the pre-accident strain demand methodology used prior to the accident may have underestimated the actual strain. Enbridge indicated that it would continue to work with its contractors to determine whether a different method is needed to apply an appropriate level of conservatism.[41]

[73] Enbridge Post-Accident Safety Improvements

Enbridge also indicated that the following safety improvements were initiated, continued, or completed.

- **Enterprise Level Changes.**
  - Enbridge Gas Transmission and Midstream (GTM) has created the framework and process documents necessary to shift its asset integrity benchmarking toward other industries with superior safety performance levels. In implementing this approach, Enbridge intends to prove the integrity of its assets using a quantitative, as opposed to a qualitative, approach to risk assessments.
  - Enbridge has significantly increased the number of ILI tool runs, and resulting number of anomaly digs, as well as staffing and budget to support the increased level of integrity work.
  - Contracted with RCP, Inc. who assessed the effectiveness of Enbridge's Public Awareness Program and its Emergency Response Program. Enbridge implemented recommended changes.

- **Geohazard Risk Ranking and Classification, and Work Process Improvements**
  - Developed a site-specific risk ranking process for classification of land movement sites based on the Joint Industry Project White Paper "Guidelines for Management of Landslide Hazards for Pipelines" published by the Interstate Natural Gas Association of America Foundation. To date, Enbridge is monitoring approximately 9,500 site groups across Enbridge US Gas Transmission and Midstream (US GTM). Currently, all identified highest risk sites (R6 and R7) have been mitigated across the system.
  - Integrated geohazard threat management information and documents into existing information management systems including work management databases and the Geographic Information System (GIS) application. Landslide susceptibility, mapped geohazard sites, and reported bending strains are now available to all Enbridge employees.
  - Updated existing and developed several new procedures and work instructions. The principles of these procedures and work instructions have been implemented as the Geohazard management program for US GTM. Newly created procedures and work instructions are:
  - Developed PI-05.719 Land Movement Interacting Anomalies Analysis Work Instruction for addressing interacting anomalies with girth welds subject to land movement;
  - Developed PI-05.725 Estimation of Axial and Bending Strain Demand Due to Land Movement Work Instruction which defines the methodology for the estimation of pipeline axial and bending strain demand induced by land movement.

- **Improvements to Geohazard Monitoring Techniques**
  - Implemented a system of Geohazard surveying techniques enabling identification and monitoring of GH sites, including:

- Enhanced Operations SOPs and activities, including Geohazard identification and monitoring training, increased aerial patrols, regional operations geohazard site visits, OOS surveys.
- Implemented land movement monitoring techniques including routine site monitoring, site visits, OOS field surveys, high-resolution mid-infrared differential absorption light detection and ranging (LiDAR) technology, and near real-time monitoring via instruments installed on site such as strain gauges, Slope Accel Arrays, and GPS.
- Installed 304 instruments at 32 land movement sites along the Affected Segment and 327 instruments at 46 sites across US GTM. Repeat high-resolution (LiDAR) imagery will be collected to identify changes at land movement sites.
- Implemented monitoring by IMU/Caliper ILI assessments on the Affected Segment for bending strain analysis of the lines and to identify land movement sites.
- Developed a preliminary precipitation monitoring system to monitor precipitation within the Appalachian Plateau as part of monitoring land movement sites on the Affected Segment.
- Updating the pipeline centerline mapping within GIS for aerial patrol reference, LiDAR imagery comparison, and field inspection.
- Implemented a multi-year project for right-of-way vegetation clearing to improve visibility on LiDAR imagery acquisition and field inspections.

- **Assessments, Monitoring Activities and Mitigation Improvements**
  - Completed geohazard mitigations at 47 geohazard sites across the Affected Segment and 87 sites total across US GTM.
  - Completed multi-disciplinary review sessions for 97 geohazard site groups resulting in requirements for enhanced monitoring, preventive or mitigative action(s) or further investigation which are recorded in Site-Specific Integrity Plans. Multi-disciplinary reviews typically include qualified individuals with backgrounds in geology, geomorphology, fluvial geomorphology, geotechnical engineering, hydrotechnical engineering, civil/structural engineering, pipeline engineering, and pipeline construction specialists, as well as Enbridge's Geohazard Group supervisor.
  - Completed 116 IMU ILI tool runs along the Affected Segment and 240 IMU ILI tool runs across US GTM.
  - Completed 240 Geotechnical field assessments carried out by subject matter experts across the Affected Segment and 700 field assessments across US GTM at land movement sites for evidence of recent landslide movement activity, relative rate of movement, evidence of a slide's depth relative to the pipelines, a slide's proximity relative to the pipeline, and measurement of pipe OOS.
  - Performed aerial instrumented leakage survey across the entirety of the Affected Segment via LiDAR technology. Enbridge is deploying this technology to the rest of the GTM system.

- Tested and deployed Atlas Wrap technology as a mitigation for reinforcement of girth welds subject to bending strain.
- Implemented rate of change limits on the suction side of Owingsville CS and other compressor stations.

Appendix A: Pipeline Operations Timeline of Events, May 4, 2020

Time	Action	Source
4:39 PM	Gas control received call attendant alarm from Owingsville CS (urgent priority)	SCADA Records
4:39 PM	Gas control received stop timer activated alarm from Owingsville CS, Units 3 and 4 (informational priority)	SCADA Records
4:40 PM	Gas Control received initial notification of possible rupture from public	Gas Controller A interview Director of Gas Control interview
4:40 PM	Field received initial notification of possible rupture from dispatch	Utility Pipeliner A interview
4:41 PM	Owingsville Area Supervisor receives initial notification of possible rupture from Utility Pipeliner A. Owingsville Area Supervisor dispatches Utility Pipeliner A to investigate.	Owingsville Area Supervisor interview Utility Pipeliner A interview
4:42 PM	Gas Controller A confirmed to Owingsville Area Supervisor that there was a pressure drop on suction side of Owingsville CS	Gas Controller A interview Owingsville Area Supervisor interview
4:44 PM	Owingsville Area Supervisor dispatched Light Equipment Operator to north Muses Mill valves at MP 517	Light Equipment Operator interview Owingsville Area Supervisor interview
4:45 PM	Owingsville Area Supervisor notifies Station Operator of possible rupture and dispatches him to Owingsville CS[74]	Station Operator interview Owingsville Area Supervisor interview
4:46 PM	Owingsville Area Supervisor dispatched Electrical Control Technician to help with isolation at Owingsville CS	Owingsville Area Supervisor interview
4:47 PM	Owingsville Area Supervisor dispatched Station Mechanic to Muses Mill to assist Light Equipment Operator	Station Mechanic interview
4:47 PM	Gas control received alarm that Owingsville CS, Units 3 and 5 were unavailable (informational priority)	SCADA Records

[74] Station Operator had left work for the day prior to the rupture.

5:00 PM	Utility Pipeliner B arrived at Owingsville CS to assist Electrical Control Technician	Utility Pipeliner B interview
5:03 PM	Electrical Control Technician manually closed the bypass valves at Owingsville CS for lines 10 and 25 (line 15 was not in service)	Electrical Control Technician interview
5:06 PM	Utility Pipeliner A arrives near accident site (Martin Mill Road access point) and asks Hillsboro Fire Department to secure the road.	Utility Pipeliner A interview
5:06 – 5:10 PM	Utility Pipeliner A confirms with contractor that all workers had left nearby job site, and no one was injured.	Utility Pipeliner A interview
5:10 PM	Utility Pipeliner A arrives near accident site (Tom Ishmael Road access point) and asks contractor to secure the road.	Utility Pipeliner A interview
5:12 PM	Station Operator arrived at Owingsville CS	Station Operator interview
5:23 PM	Light Equipment Operator confirmed valves 10-367, 15-522, 25-725 were closed	Light Equipment Operator interview Owingsville Area Supervisor interview
5:26 PM	Station Operator shut DCO-1, DCO-2, DCO-3, SCO-1, SCO-2, and SCO-3	Electrical Control Technician interview
5:29 PM	Gas control confirmed affected valve section was isolated	Owingsville Area Supervisor interview
5:40 PM	Gas control confirmed ruptured segment was isolated	Station Operator interview
6:00 PM	Utility Pipeliner B arrived on the right-of-way near the accident site to secure the location	Utility Pipeliner B interview
6:10 PM	Stanford Area Manager directed Station Operator to blowdown lines 15 and 25 to 50 psig from Owingsville CS to Muses Mill	Station Operator interview
6:58 PM	Station Operator began blow down of first section north of Owingsville CS for lines 15 and 25	Station Operator interview
9:05 PM	Received direction to blowdown lines 15 and 25 to 0 psig from Owingsville to Muses Mill stations	Station Operator interview
9:20 PM	Blowdown was complete and flames died down. Leak detection performed at accident	Light Equipment Operator interview

	site with flame ionization detector. Forestry Service permitted to put out small fires.	
11:48 PM	Enbridge sent two employees to both the north and south ends to secure the site for the night	Owingsville Area Supervisor interview
1:32 AM	Received confirmation that the residual flames were out[75]	Owingsville Area Supervisor interview Light Equipment Operator interview

[75] Local authorities were not allowed to access the site to battle or extinguish any secondary fires until Enbridge granted access and deemed it safe to enter (Owingsville Area Supervisor interview).

Appendix B: Site Photos

Figure 8. Ruptured girth weld, taken May 5, 2020 at 12:11PM (Courtesy of Enbridge)

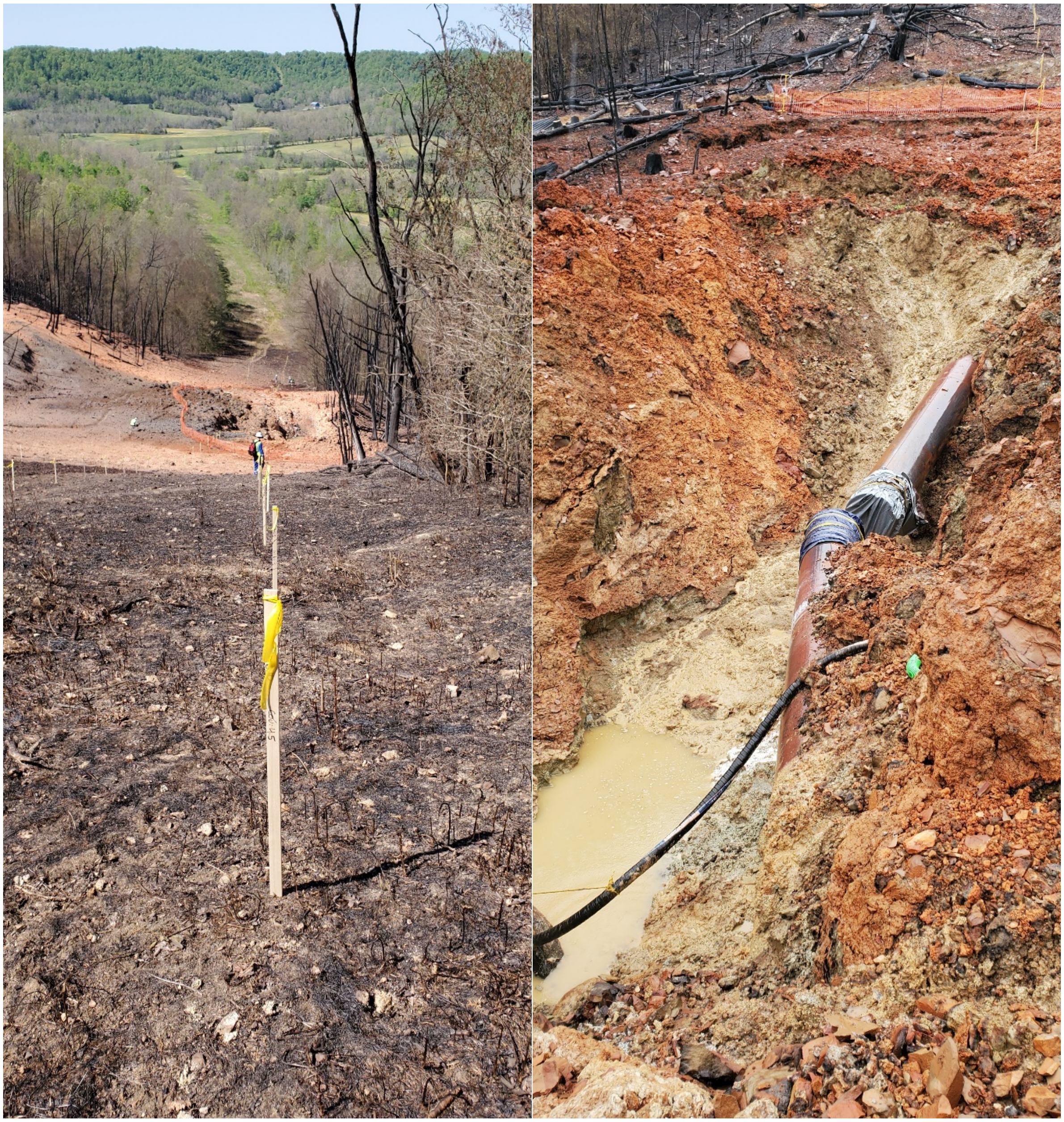

Figure 9. Left, Line 10 right-of-way after locating, taken May 7, 2020 at 11:21AM. Right, Line 10 failure location with fracture surfaces protected, taken May 8, 2020 at 2:48PM (Courtesy of BGC)

Figure 10. Site surrounding ruptured girth weld, taken May 7, 2020 at 1:42PM (Courtesy of BGC)

Figure 11. Site surrounding ruptured girth weld during excavation, taken May 11, 2020 at 4:57PM (Courtesy of BGC)