Failure Investigation Report

South Bow Infrastructure Operations Inc.

Executive Summary

On April 8, 2025, at 7:42 a.m.,[1] a segment of the Keystone Pipeline ruptured, releasing approximately 3,500 barrels of crude oil into an agricultural field near Kathryn, North Dakota. The rupture occurred in the vicinity of Milepost 171 (MP 171), approximately 1,648 feet downstream of the Fort Ransom Pumping Station.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) deployed four accident investigators and three inspectors in response to the failure. Based on its preliminary findings, PHMSA issued a Corrective Action Order (CAO), CPF No. 3-2025-018-CAO, to South Bow Infrastructure Operations Inc. (South Bow), the operator of the Keystone Pipeline, on April 11, 2025.[2] The CAO directed South Bow to perform a number of actions, including conducting a metallurgical analysis of the failed pipe segment and completing a root cause failure analysis (RCFA) of the event.

PHMSA has reviewed the results of the metallurgical analysis and RCFA and determined that the cause of the rupture was a pipe manufacturing defect. A fatigue crack had formed at the interior toe of the long seam during original transport due to angular misalignment[3] and significant misalignment between the internal and external deposited submerged arc welds[4]. That initial, transportation-related crack grew over time due to in-service pressure cycling, which allowed environmental fatigue to occur until the remaining region could no longer support the hoop stress of the pipeline operation. The revealed findings and contributing factors include:

- The pipe manufacturing inspection process failed to identify the angular misalignment and weld bead misalignment.
    - These unidentified manufacturing defects acted as stress concentrators that allowed a crack to initiate during the pipe transportation process, and that crack ultimately ruptured due to subsequent in-service pressure cycling and environmental fatigue.
- The operators of the Keystone Pipeline did not have an effective crack management program and, as a result, failed to identify the crack at MP 171 that grew incrementally over a 15-year period before the rupture.
    - The Keystone Pipeline had higher fatigue-inducing operational cycles when the system originally went into service. While subsequent measures were taken to reduce the frequency of these operational cycles, they did not prevent the rupture that occurred at MP 171.

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[1] All times listed in Central Daylight Time throughout the report.

[2] CPF 3-2025-018-CAO, *available at* [https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2025-04/PHMSA%20CAO_South%20Bow-Keystone%20CPF%203%202025%20018.pdf.](https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2025-04/PHMSA%20CAO_South%20Bow-Keystone%20CPF%203%202025%20018.pdf)

[3] Angular misalignment (also known as roof topping or peaking) refers to the angle at which the ends of the plate come together to form the pipe. Ideally, these form a 180° angle at the weld. Misalignment occurs when the centerlines of the two ends of the plate are not perfectly aligned along the same axis, but instead form an angle.

[4] Double Submerged Arc Welded (DSAW) bead misalignment refers to the vertical alignment of the inside diameter (ID) DSAW and the outside diameter (OD) DSAW weld beads. Ideally these are centered on the same axis perpendicular to the pipe surfaces.

- Ultrasonic crack detection technology was primarily used to identify cracks in the Keystone Pipeline.
- With the history of cracking failures and the apparent inability to identify and remediate cracks prior to failure, hydrostatic spike testing to 103%-105% of Specified Minimum Yield Strength (SMYS) could have been used as a complementary assessment method to confirm the reliability of South Bow's crack management program and to provide additional confirmation of the pipeline's integrity. It was not used.

- Hydrogen-induced cracking (HIC) was identified in the fracture surface. The presence of hydrogen is known to reduce steel toughness.

1. Summary of the April 8, 2025, South Bow Failure

Lead Investigator	Tim Disher
Accident Investigation Director	Chris Ruhl
Date of Report	March 11, 2026
Date of Failure	April 8, 2025
Commodity Released	Crude Oil
City, County, and State	Kathryn, Ransom County, North Dakota
OpID and Operator Name	32334 – South Bow Infrastructure Operations Inc.
Unit # & Unit Name	72676 – Keystone Mainline #1
WMS Activity #	25-338014
Milepost / Location	MP 171, 46.583056, -97.936667
Type of Failure	Material Failure of Pipe or Weld – Design-, Construction-, Installation-, or Fabrication-Related
Fatalities	None
Injuries	None
Description of Impacted Area	Agricultural field
Total Costs	$52,731,684

2. System Description

South Bow's Keystone Pipeline system originates in Hardisty, Alberta, Canada and transports crude oil to terminals in Patoka, Illinois, and Cushing, Oklahoma. The United States portion of the pipeline begins north of Walhalla, North Dakota, and comprises approximately 1,855 miles of pipeline through North Dakota, South Dakota, Nebraska, Kansas, Missouri, Illinois, Oklahoma, and Texas as shown in **Figure 1**. TC Energy, formally known as TransCanada Pipelines, originally constructed the Keystone Pipeline, which was placed into service in 2010. TC Energy transferred operating responsibility for the Keystone Pipeline to South Bow on March 22, 2024.

The Keystone Pipeline comprises two segments: (1) the Keystone Mainline, and (2) the Keystone Cushing Extension. PHMSA has issued special permits that apply to both segments. The special permits allow the Keystone Mainline and Keystone Cushing Extension to operate at a stress level of up to 80% of SMYS of the pipe, subject to 51 specific conditions and additional limitations and exclusions.[5] The maximum operating pressure (MOP) of the segments could not exceed 72% SMYS without the special permits. PHMSA reimposed the 72% of SMYS limit for the Keystone Pipeline in the CAOs issued in response to prior failures.

The Keystone Mainline runs approximately 1,084 miles across the states of North Dakota, South Dakota, Nebraska, Kansas, Missouri, and Illinois. The April 8, 2025 rupture occurred on the Keystone Mainline in the vicinity of Milepost 171. This pipeline segment has a diameter of 30 inches and an MOP of 1,440 psig. The location of the failure is depicted in **Figure 2** below.

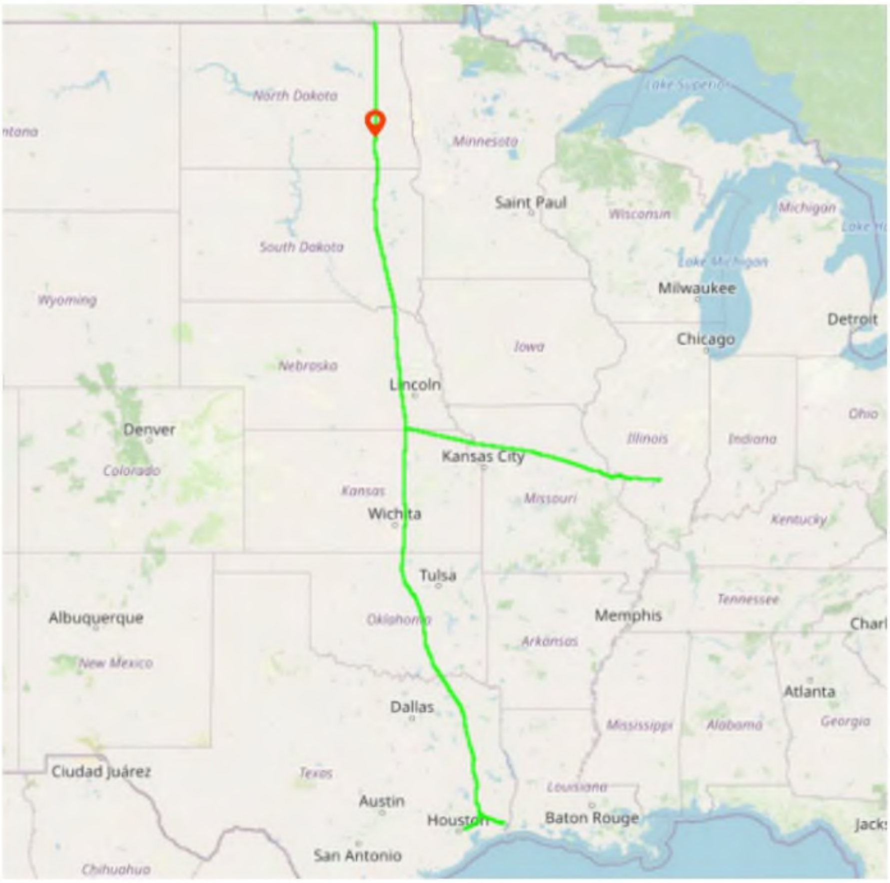

Figure 1. South Bow System as shown on NPMS with release site marked.

[5] Special Permit, November 17, 2006, PHMSA-2006-26617 *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/TC_Keystone_2007-04-30_508compliant.pdf.

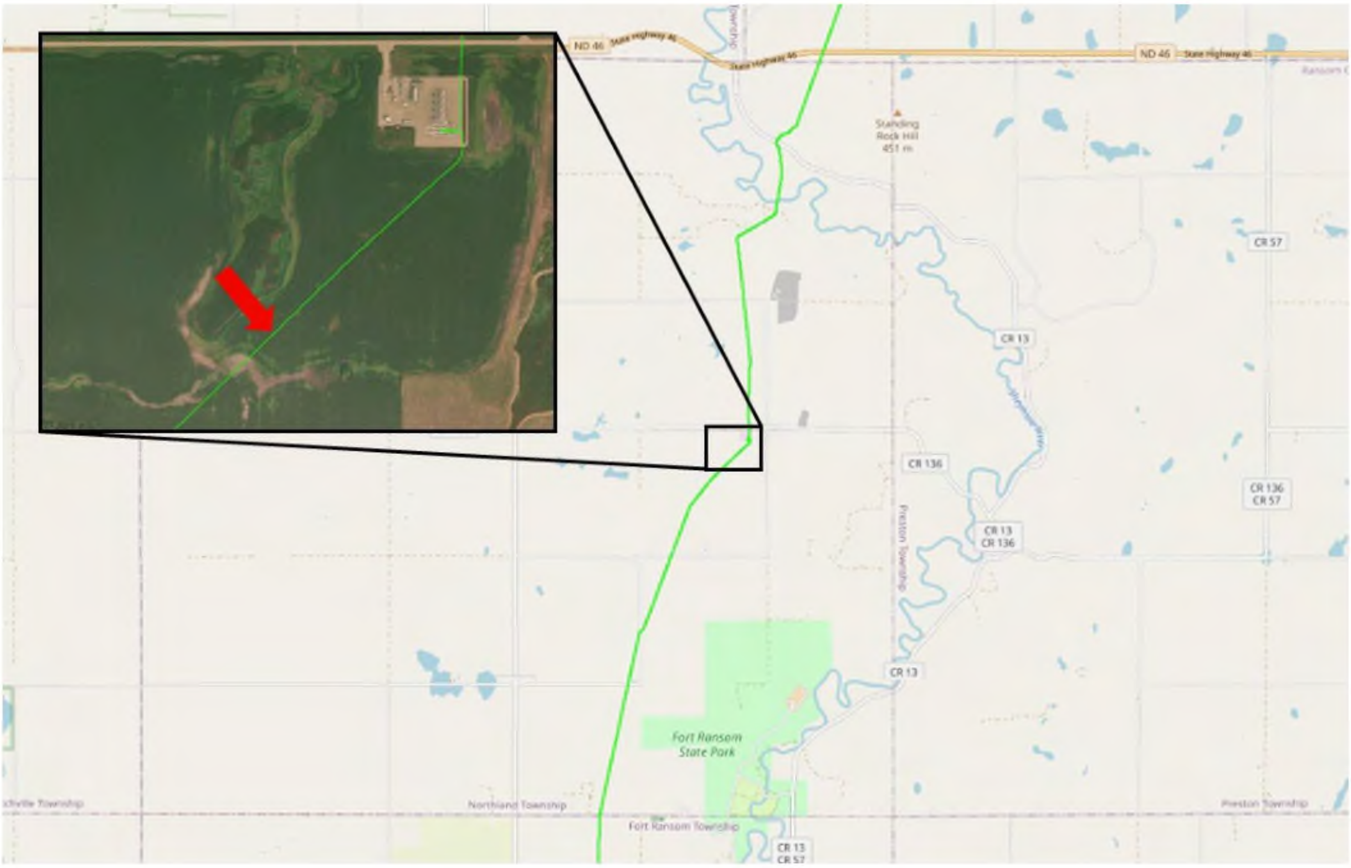

Figure 2. Location of Event.

3. Events Leading up to the Failure

The Keystone Pipeline has had more than 20 failures since being placed into operation in 2010.[6] The more noteworthy failures include:

- April 2, 2016 – Crude oil leaked from a cracked tie-in girth weld located between the Freeman Pump Station and Hartington Pump Station on the Keystone Mainline. The total release volume was 400 barrels of crude oil. PHMSA issued a CAO in response to this release.[7]
- November 16, 2017 – Crude oil was released from a fracture caused by mechanical damage from a backhoe track during initial construction. The failure released 6,592 barrels of crude oil. PHMSA issued a CAO in response to this release.[8]

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[6] Pipeline Safety: Information on Keystone Accidents and DOT Oversight, GAO-21-588 (Jul. 22, 2021), https://www.gao.gov/products/gao-21-588.

[7] CPF 320165002H, April 9, 2016, *available at* https://primis.phmsa.dot.gov/enforcement-documents/320165003H/320165003H_Corrective%20Action%20Order_04092016.pdf.

[8] CPF 320175008H, November 28, 2017, *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/56511/320175008h-corrective-action-order-transcanada-11282017.pdf.

- February 6, 2019 – Seventeen barrels of crude oil were released when a crack formed in a previously repaired section of pipe where composite wrap had been installed due to indications of metal loss. The crack exhibited signs of fatigue.
- October 29, 2019 – A longitudinal seam failure occurred between the Edinburg Pump Station and Niagara Pump Station on the Keystone Mainline, resulting in a release of 4,515 barrels of crude oil. PHMSA issued a CAO in response to this release.[9]
- December 7, 2022 – A girth weld failed near Washington, Kansas, on the Keystone Cushing Extension, resulting in a release of 12,937 barrels of crude oil. PHMSA issued a CAO following the failure, limiting the MOP of the entire Keystone Pipeline to 72% of SMYS (1296 psig).[10, 11] The MOP limitation remains in effect.

4. Details Regarding the April 8, 2025 failure at MP 171

Berg Steel Pipe Corporation (Berg) manufactured the pipe that failed at MP 171 some time between May 2008 and September 2008. Installation occurred in 2008, and the pipe went into service in 2010. Records indicate that multiple In-Line-Inspection (ILI) tools were used to assess the integrity of the pipeline on the following dates:

- Two ILI utilizing ultrasonic crack technology (April 2020 and September 2020)
- One ILI utilizing caliper technology (October 2021)
- One ILI utilizing ultrasonic technology to detect metal loss (July 2021)
- One ILI utilizing ultrasonic crack circumferential technology (November 2023)

The April 8, 2025 rupture occurred during normal operations. On the day of the failure, a South Bow employee was performing maintenance on the Fort Ransom Pump Station Unit 4. Unit 2 and Unit 3 were operating at the time. The following is an approximate timeline for the day of the rupture, compiled using PHMSA interviews of employees and South Bow's records.

- 6:00 a.m. – South Bow initiated a throughput rate reduction at several pump stations along the Keystone Mainline to conduct scheduled maintenance.
- 6:14 a.m. – South Bow's Control Room observed a decrease in the throughput rate as intended at the Fort Ransom Pump Station.

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[9] CPF 320195023H, November 5, 2019, *available at* https://primis.phmsa.dot.gov/enforcement-documents/320195023H/320195023H_Corrective%20Action%20Order_11052019_text.pdf.

[10] CPF 3-2022-074-CAO, December 8, 2022, *available at* https://primis.phmsa.dot.gov/enforcement-documents/32022074CAO/32022074CAO_Corrective%20Action%20Order_12082022_(22-261792).pdff.

[11] CPF 3-2022-074-CAO, March 7, 2023, *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-03/TC%20Oil%20Pipeline%20-%2032022074CAO_Amended%20Corrective%20Action%20Order_03072023_(22-261792).pdf

- 6:40 a.m. – A South Bow employee arrived on site and began maintenance work on Unit 4, which had been taken out of service for maintenance.
- 7:42 a.m. – The rupture occurred. The South Bow employee heard a "different sound" followed by a "bang" and then witnessed oil spraying into the air across the field next to the pump station. The control center's Leak Detection System (LDS) identified a loss of flow between Fort Ransom Pump Station and Ludden Pump Station.

Those interviewed by PHMSA following the failure did not express any indications that something was wrong prior to the release. The temperature in Kathryn, North Dakota, was approximately 26°F, with no precipitation recorded during the prior 24 hours.

5. Emergency Response Procedures After the Failure

After the release, the following events took place on April 8, 2025:

- 7:43:02 a.m. – A South Bow employee initiated an on-site Emergency Shutdown (ESD) at Fort Ransom Pump Station, which terminated flow through the station and isolated it from pipeline sections upstream and downstream. A South Bow employee contacted South Bow's Liquid Pipeline Control Centre (LPCC) in Calgary, Alberta, Canada, to report the release.
- 7:43:43 a.m. – LPCC initiated a full pipeline shutdown.
- 7:48 a.m. – LPCC personnel began contacting local first responders, South Bow's regional Emergency Operations Center (EOC), South Bow regulatory compliance, oil scheduling, and operations engineering. These outreach efforts continued until 8:19 a.m.
- 7:50 a.m. – Complete isolation of the failed segment was achieved, with motor-operated valves closed at the Fort Ransom pump station and at a valve site 9.5 miles south of Fort Ransom (FTRSM+09_5).
- 8:46 a.m. – South Bow notified the National Response Center (NRC). The NRC assigned Report Number 1428025 to the notification.
- 10:52 a.m. – South Bow contacted Oil Spill Removal Organizations (OSRO) to activate clean-up resources.
- 4:45 p.m. – OSRO arrived on scene.

On April 10, 2025, at 9:54 a.m., South Bow provided an update to the NRC (NRC Report No. 1428221). On April 13, 2025, a representative from Anderson & Associates (Anderson), an independent metallurgical contractor, was present for the selection and removal of the ruptured pipe segment. South Bow removed an approximate 60-foot section of pipe from the pipeline, cut it into two segments, and wrapped it for shipping. The pipe segments were transported following chain-of-custody procedures on a flat-bed trailer truck to Anderson's facility in Houston, Texas, leaving the accident site on April 16, 2025.

5. Summary of Return-to-Service

As a result of the failure, PHMSA issued a CAO, CPF No. 3-2025-018-CAO, to South Bow.[12] South Bow developed repair and restart plans, which PHMSA's Central Region Director reviewed. PHMSA dispatched three regional inspectors to observe South Bow's repair activities. South Bow completed the repairs and returned the pipeline to service at 8:19 p.m. on April 16, 2025, in compliance with a PHMSA-imposed 20% pressure reduction of the operating pressure.

The design pressure of the pipe is 1,440 psig. At the time of the April 8, 2025 failure, the MOP of the pipeline was limited to 72% of SMYS (1,296 psig), per the terms of a 2023 CAO, CPF No. 3-2022-074-CAO.[13] The actual operating pressure at the time of failure was 1,252 psig. The pipeline was restarted with an MOP of 1,000 psig measured at the Fort Ransom pump station discharge, complying with the most recent CAO. In addition, PHMSA's CAO further directed South Bow to decrease the MOP on all sections of the Keystone system where the pipeline's diameter, seam type, and manufacturing characteristics were consistent with the section of pipe that failed on April 8, 2025.

6. Investigation Details

PHMSA deployed four investigators and three inspectors to Kathryn, North Dakota, with at least one investigator remaining on site each day from April 8 through April 16, 2025. PHMSA Central Region deployed two inspectors to Calgary, Canada, to investigate the LPCC and conduct interviews of control room operators on April 9 and April 10, 2025. PHMSA investigators also traveled to Houston, Texas, to observe Anderson's metallurgical testing between April 28 and May 3, 2025, and again between May 5 and May 7, 2025. In addition to metallurgical testing conducted by Anderson, South Bow also retained Blade Energy Partners as an independent third party to perform an RCFA, consistent with the PHMSA directives contained in the most recent CAO. PHMSA's investigation was broken down into three areas of focus:

1. Manufactured Pipe – Metallurgical analysis conducted on the failed segment;
2. Hazard Identification – Detection protocols and results from ILI; and
3. General Operations – Control room activity and operational considerations.

As part of the investigation, PHMSA interviewed a total of five people, listed in **Table 1**. The interviewees have been grouped by affiliation for added anonymity.

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[12] CPF 3-2025-018-CAO, *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2025-04/PHMSA%20CAO_South%20Bow-Keystone%20CPF%203%202025%20018.pdf.

[13] *See* CPF 3-2022-074-CAO, March 7, 2023, *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-03/TC%20Oil%20Pipeline%20-%2032022074CAO_Amended%20Corrective%20Action%20Order_03072023_(22-261792).pdf.

Table 1. List of Interviewees.

Interview Numbers	Affiliation	Role(s)	Witness	Date of Interview
I01, I02, I04, I05	South Bow	EIC/Mechanic; Electrical Field Specialist; Supervisor Controller; Trainee Controller	Yes (1), No (3)	April 9, 2025; April 10, 2025
I03	Private Individual	Land Lease Holder	No (1)	April 9, 2025

A. Manufactured Pipe

The ruptured pipe had a diameter of 30 inches with a nominal wall thickness of 0.386 inches. The pipe was manufactured with a Double Submerged Arc Weld (DSAW) to create a longitudinal seam consistent with the American Petroleum Institute's (API) pipe manufacturing specifications designated as API 5L X70 PSL 2. The pipe was coated with a Fusion-Bonded Epoxy coating (FBE).

General Findings

The feature of interest is shown in **Figure 3**, which shows a fish-mouth split that originated along the long seam of the pipe. The center portion of the fish-mouth split exhibits signs of fatigue measuring 11.9 inches, with a maximum measured depth of 0.302 inches where the crack penetrated 79.3% of the measured actual wall thickness.

Figure 3. Fish Mouth Feature, Photo from Anderson & Associated Report.

In conducting the metallurgical testing, Anderson examined the failed specimen using a Scanning Electron Microscope (SEM), with the SEM analysis revealing some features of interest. The fractured surface showed indications of fatigue due to progressive cracking. The images presented in **Figure 4** show the depth of the crack prior to the final break, as well as the beach lines,[14] indicating how the crack propagated. In **Figure 4** below, the area identified as "Figure 16" depicts evidence of hydrogen-induced cracking (HIC). HIC occurs when hydrogen atoms diffuse into the steel and accumulate around existing crack tips, causing localized stain buildup and accelerated crack growth.

The Blade RCFA Report identified higher levels of hydrogen present in the ruptured joint and the adjacent downstream joint compared to an unused pipe joint left over from construction. Blade noted that diluted bitumen (dilbit)[15] transported by the Keystone pipeline contains a host of compounds, including iron sulfide, sulfur, water, and naphthenic acid, which can produce hydrogen sulfide (H2S). H2S in an aqueous environment can provide a source of hydrogen atoms which may accelerate crack growth.

A close-up view of this area is shown in **Figure 4** and denotes three zones. Zone I indicates the transportation-related fatigue crack. Zone II shows the environmental fatigue-related crack progression. Zone III shows the shear overload region when the steel could no longer support the hoop stress caused by the pressure in the pipe. The green material in the figure is the FBE coating.

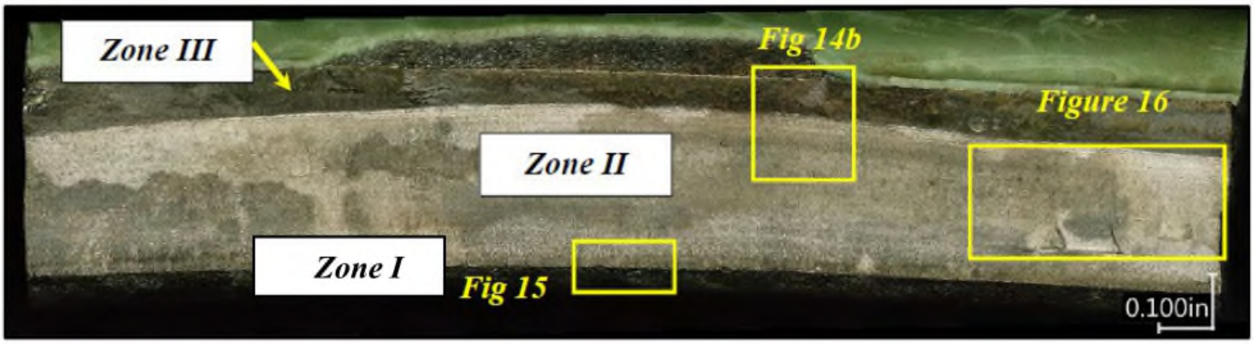

Figure 4. Low Magnification views Detailing Crack Features and Arrest Lines.
Image from Anderson & Associated Report.

Further metallurgical analysis detected evidence of hydrogen due to secondary cracking perpendicular to the primary fracture surface. These secondary cracks are a sign of HIC and appeared across approximately 3% of the length of the primary fracture surface. These secondary cracks indicate the presence of hydrogen in the steel, which reduces toughness. These secondary cracks are located perpendicular to the primary fracture surface. They did not substantially contribute to the progress of the primary crack in Zone II. **Figure 5** shows these features.

[14] "Beach lines" are a series of concentric lines or arcs created by crack growth.

[15] Dilbit is a heavy, viscous crude oil extracted from Canadian oil sands that is often mixed with lighter hydrocarbon solvents to facilitate pipeline transportation.

Figure 5. Crack features identified on the fracture surface, consistent with HIC.

Photo from Anderson & Associates Report.

Pressure Cycles

Blade Energy Partners analyzed the pressure cycle records from the commencement of operations in 2010 to the date of the failure. Over that time, a total of 529.6 cycles occurred, with a cycle pressure of 1,348 psig. A crack at the depth observed would not be expected given the pipe specification, the number of pressure cycles, and the cycle pressure. This analysis concluded that a crack had to exist in the pipe prior to 2010.

Pipeline Manufacture

Berg manufactured the pipe that ruptured in 2008 at a facility located in Panama City, Florida. The pipe was manufactured with a straight longitudinal seam using submerged arc welding consistent with specifications contained in API 5L, 43rd edition.

Of note, the 44th Edition of API 5L was formally released for review in October 2007 and ultimately adopted in October 2008. All three production runs of Berg pipe produced for the Keystone project occurred prior to the adoption of the 44th Edition. One notable change in the 44th Edition was the addition of rejection criteria for instances of misalignment of weld beads along DSAW seams. The updated API requirement applies to pipes with a wall thickness of less than 0.8 inches, with maximum allowed weld bead misalignment of 0.1181-inch (3mm). The section of pipe that ruptured in April 2025 contained weld beads that were clearly misaligned, with one misalignment measuring 0.1456-inch (3.7 mm) in the 0.386" wall thickness pipe. In no case would this section of pipe meet the more stringent requirements of the 44th Edition.

In addition, TransCanada's Engineering Specification, TES-PIPESAW-US, required pipe manufacturing specifications with higher tolerances than those contained in API 5L 43rd Edition. Berg failed to meet the additional specifications in the failed joint. Metallurgical observations indicate the non-compliance with TransCanada's more stringent specification regarding angular misalignment, weld bead misalignment, and plate end offset.

According to Berg's Materials Testing Record (MTR) Heat Number 181P47530, Charpy impact tests on the heat affected zone (HAZ) for the ruptured joint ranged from 1380 to 1584 lbf/in. Anderson tested the failed pipe joint for toughness and the presence of hydrogen after the April 2025 failure. Blade conducted a comparative analysis of the in-service ruptured pipe before and after a hydrogen bake-out.[16] Toughness values for the DSAW HAZ (Ju[17]) around the failed joint ranged from 646 to 1,471 lbf/in. Toughness values for the same failed joint after the hydrogen bake-out (400 degrees F for 30 minutes) increased to 1,839 to 2,513 lbf/in. The difference in toughness as it relates to hydrogen is theorized to be related to pipeline operation and/or the transport of crude oil. Of note, toughness testing of an unused joint of pipe from original stock had toughness values Ju for the HAZ ranging from 313 to 725 lbf/in. The results indicate that the unused pipe had lower toughness values than in-service pipe. The root cause report did not go into further explanation and left this concern unaddressed as an open item.

The special permit for the Keystone Pipeline included provisions for transportation of the pipe. The provision required that the pipe delivered by rail car must be transported according to the API Recommended Practice 5L1, "Railroad Transportation of Line Pipe." The recommended practice specifies how the pipe should be supported, stacked, and oriented on the train car to prevent transportation fatigue and damage to the long seam. PHMSA personnel inspected a few loaded rail cars during construction and did not find any issues with the transportation process. The special permit requirements and inspections do not rule out individual segments of pipe being subject to transportation-related fatigue during shipment.

B. Hazard Identification

Between the October 2019 Edinburg and MP 171 failures, South Bow conducted five ILIs to detect anomalies in the ruptured segment. They included two inspections that used ultrasonic crack technology (April 2020 and September 2020), one that used caliper technology (October 2021), one that used ultrasonic wall assessment of metal loss (July 2021), and one that used an ultrasonic crack circumference tool (November 2023). Of the ILI tools utilized, the two with ultrasonic crack technology were most likely to detect crack-like features along the seam weld. Though the transportation-related crack features are believed to have existed prior to pipeline operation and continued to grow once it was put into service, no cracks were detected at the MP 171 failure location.

C. General Operations

PHMSA reviewed South Bow's response to the event for compliance with their Facility Response Plan (FRP). **Table 2** shows the standards contained in the FRP that South Bow submitted to PHMSA. Timeframes from the time of failure to response actions were within the range established by the FRP.

Rapid field confirmation was possible due to the on-site South Bow personnel who heard the rupture and notified the LPCC. The prompt response likely reduced the volume of the release.

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[16] Hydrogen bake-out involves heating steel to an elevated temperature and holding the temperature for a specific time to allow hydrogen to diffuse from the steel. The reduction of hydrogen prevents cracking and increases toughness.

[17] Ju is the unit of measure for the energy required to initiate rapid unstable crack growth.

Table 2. South Bow Response Standards

FRP Phase	Response Time Standard	Actions	Response Time at MP 171
Phase 1	Initiated immediately upon recognition of a pipeline emergency	Pipeline Shutdown Isolation	8 minutes, 25 seconds – pipeline fully isolated
Phase 2	2 Hours	Emergency Response Activities	17 minutes – an Incident Commander arrived on site
Phase 3	3 Hours	Staff on-site	18 minutes – arrived at scene of failure
Phase 4	6 Hours	Initial Emergency Response Equipment on-site	3 hours – trailer arrived with equipment to construct berms to contain the surface flow of crude oil

As part of the investigation, members of the PHMSA Control Room Management Team interviewed a South Bow supervisor controller and a trainee controller and reviewed control room logs at the LPCC. The response from the control room was rapid, with the full shutdown initiated by the LPCC 41 seconds after a South Bow employee initiated the emergency shutdown at Fort Ransom Pump Station. The trainee controller was operating the Keystone Mainline console at the time the rupture occurred. This controller was on the second day of a 5-day shift and self-reported no fatigue at the time of the rupture. The trainee controller worked as a controller in various other roles since 2001, including as a TC Energy controller beginning in 2021, with a subsequent transfer to South Bow. The trainee controller was also near the end of the training program and was supervised by the OQ-qualified supervisor controller. PHMSA's review of the LPCC did not identify fatigue, lack of experience, or other human factors as contributing factors to the rupture or the magnitude of the release.

D. PHMSA Analysis of Anderson & Associates Metallurgical and Blade Energy Partners Root Cause Findings:

- At the time of the rupture, the pipe had previously been subjected to 529.6 fatigue cycles at 1,348 psig operating pressure. This fatigue spectrum would not typically cause a rupture in a crude oil pipeline, but several factors discussed below created exceptional circumstances.
- Angular misalignment of approximately 12 to 15 degrees of the DSAW long seam contributed to the rupture (the pipe radius of curvature was not uniform circumferentially across the long seam).
- A crack through approximately 10% of the wall thickness was present at the toe of the inside submerged arc weld before the pipeline was placed in-service, The crack was likely caused by the interaction of angular misalignment, possible micro-corrosion at the toe of the internal submerged arc weld, and railroad fatigue, truck transport fatigue, or a combination of the two.

- There was a physical lateral offset of 3.7 mm between the inner diameter (ID) and outer diameter (OD) of the submerged arc welds. This lateral offset increased the stress intensification associated with the crack initiation. This offset was not considered a defect under the 43rd Edition of API 5L but was added as a defect to the API 5L 44th Edition.
- The pipe joint that ruptured did not meet Keystone pipe purchase specifications, which set limits on angular misalignment, weld bead misalignment, and plate end offset.
- Fatigue striations on the fracture surface were created when the pipe was exposed to atmospheric conditions, indicating transportation fatigue. The in-service environmental fatigue indications that were identified on the fracture surface are attributed to the equivalent of 529.6 fatigue cycles at 1,348 psig operating pressure.
- The chemical analysis of the ruptured pipe, weld seam, and HAZ was compared to unused pipe, and elevated levels of hydrogen were found in the ruptured pipe.
- X-ray Photoelectron Spectroscopy of the fracture surface identified iron sulfide and iron sulfate, which suggests an electrochemical mechanism for the presence of hydrogen in the fatigue crack. This relates to a possible environmental cracking relationship with the transport of crude oil along with up to 0.5% water.
- The October 2019 Edinburg rupture had similar causal factors as the MP 171 rupture. Specifically, angular misalignment and low fatigue cycles were present in both failures. The Edinburg rupture had radial offset (high-low),[18] which was not found in the MP 171 investigation.
- Following the October 2019 Edinburg rupture, Keystone modified the ILI program using ultrasonic shear wave technology, specifically targeting crack identification in or adjacent to the DSAW long seam. The program failed to identify the MP 171 crack before the pipeline ruptured.

E. 2019 Edinburg Accident

Cyclic fatigue cracking along the DSAW longitudinal seam caused the October 2019 Edinburg rupture. Multiple fatigue cracks propagated from small corrosion pits identified along the inside weld toe. The fatigue cracks coalesced and progressed linearly across the wall thickness until the remaining region could no longer support the hoop stress caused by the operation of the pipeline. At the rupture origin there was angular misalignment and radial offset (high-low). The radial offset exceeded the acceptable limits of API 5L, 43rd Edition, and TransCanada's more stringent Engineering Specification guidelines under TES-PIPE_SAW-US. In the Edinburg incident, RSI Pipeline Solutions (RSI) was contracted as a third-party investigator to investigate the rupture. RSI's root cause investigation relied on the results of a finite element analysis (FEA). The FEA concluded that weld geometry subjected the failed section of pipe to significant concentrated loads that likely initiated the cracking. Other causal factors noted were poor pipe manufacturing practices, poor pipe inspection practice, and prior in-line inspections failing to identify cracking. RSI ruled out the possibility of transportation fatigue as a cause.

[18] Radial offset (high-low) refers to the alignment of the edges of the plate, where the inner diameter (ID) and outer diameter (OD) surfaces do not align.

Comparison of MP 171 and Edinburg Ruptures

The October 29, 2019, Edinburg failure was similar to the MP 171 failure. Several of these similarities are provided in **Table 3**. This table compiles information from Root Cause Analysis Reports, Metallurgical Reports, the PHMSA Edinburg report, and findings from AID's current investigation.

Table 3. Comparison of MP 171 and Edinburg findings

CATEGORY	MP 171 FAILURE	EDINBURG FAILURE
PIPE OVERVIEW	30" diameter; wall thickness 0.386" (actual 0.335" to 0.406"); API 5L X70 PSL2; coated with FBE	30" diameter; wall thickness 0.386" (actual 0.388" to 0.393"); API 5L X70 PSL2; coated with FBE
PIPE MANUFACTURER	Berg in 2008; manufactured to API 5L 43rd Edition	Berg in 2008; manufactured to API 5L 43rd Edition
VISUAL FINDINGS	No evidence of mechanical damage such as scratches, dents, and dings.	No evidence of mechanical damage such as scratches, dents, and dings.
ORIGIN OF CRACK	ID weld toe of seam weld; corrosion micropitting along the weld toe of unknown origin date. Transportation fatigue.	ID weld toe of seam weld; corrosion micropitting along the weld toe of unknown origin date. Angular misalignment and radial offset (high-low).
REPORTED MECHANISM OF FAILURE	Transportation Fatigue Environmental fatigue cracking	Fatigue (Progressive) cracking
NUMBER OF PRESSURE CYCLES	529.6 fatigue cycles at the 1348 psig	291.4 total full pressure fatigue cycles
DISTANCE DOWNSTREAM OF PUMP STATION	1,648 feet	~300 feet
HYDROGEN	Reported as an explanation for the brittle nature of the failure and identified in a small section of the fatigue region. Hydrogen bake-out test confirmed hydrogen.	Reduced toughness due to the presence of hydrogen and/or environmental cracking during crude oil transport were not investigated.

CATEGORY	MP 171 FAILURE	EDINBURG FAILURE
WELD BEAD MISALIGNMENT	Visually misaligned and confirmed through laboratory analysis.	Visually misaligned in report images.
ANGULAR MISALIGNMENT	Observed, maximum measured offset angle of 15.909 degrees	Observed, maximum measured offset angle of approximately 15 degrees

The overall findings of these reports show some similar failure mechanisms. In the figures below, the visual similarities between features from the two failures are shown. Both failures involved micropitting corrosion at the ID toe of the DSAW long seam as shown in **Figure 6** and **Figure 7**. Corrosion that occurred before pipe transportation could have amplified transportation fatigue, as it would have provided a stress concentrator. Corrosion occurring after the pipe was transported or placed in service would have no effect on the failure as the transportation fatigue crack would have already occurred.

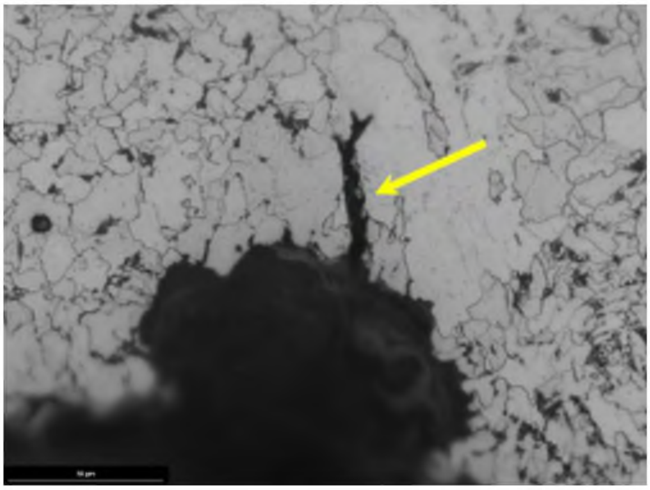


Figure 6. Corrosion micropitting at long seam weld toe from MP 171 Release (Image from 2025 Anderson & Associates report)

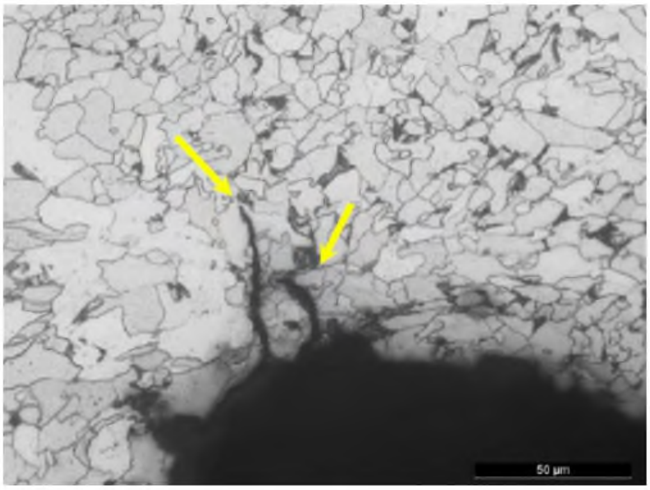
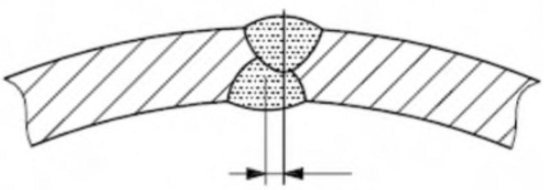


Figure 7. Corrosion micropitting at long seam weld toe from Edinburg Failure (Image from 2019 Anderson & Associates report)

A depiction of weld bead misalignment is shown below in **Figure 8**, and an example depiction of angular misalignment is shown in **Figure 9**. The DSAW long seams from the two failures showed very similar weld bead misalignment (**Figures 10** and **11**). Finally, there was angular misalignment observed on both pipes, shown in **Figures 12** and **13**.



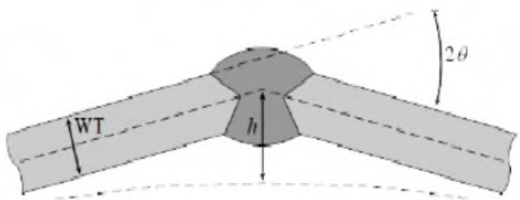


Figure 8. Example depiction of weld bead misalignment

Figure 9. Example depiction of angular misalignment

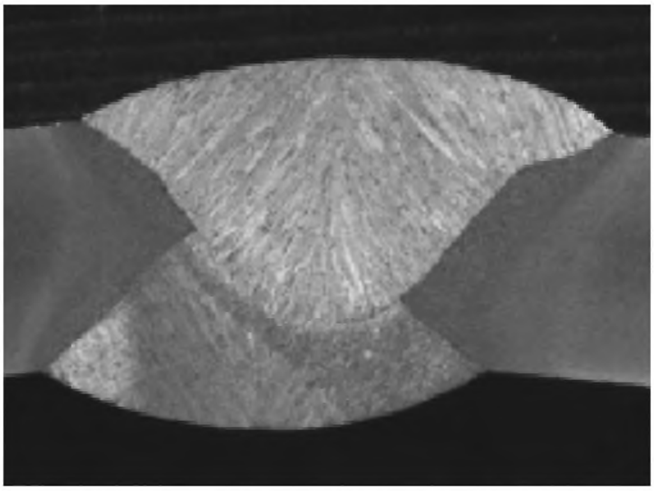


Figure 10. Visual Seam Misalignment from MP 171 Failure (Image from 2025 Anderson & Associates report)

(b)(4)

Figure 11. Visual Seam Misalignment from Edinburg Failure (Image from RSI Pipeline Solutions report)

(b)(4)

Figure 12. Angular misalignment from MP 171 Failure (Image from 2025 Anderson & Associates report)

Figure 13. Angular misalignment from Edinburg Failure (Image from RSI Pipeline Solutions report)

For the Edinburg failure, the pipe seam geometry was examined for its theoretical fatigue life with and without corrosion present. The actual seam geometry and the ideal seam geometry were compared. Without corrosion, the ideal seam had a theoretical fatigue life of 64.4 years, while corrosion pits reduced it to 41.8 years. The difference is less drastic for the actual seam; however, the total theoretical fatigue life reduction was only 10.1 years without corrosion and 9.4 years with corrosion.

Hydrogen's role in reducing toughness and the influence of crude oil on environmental cracking identified in the MP 171 rupture were not investigated for the 2019 Edinburg failure.

RSI's root cause investigation of the 2019 Edinburg failure considered railroad fatigue and suspected the possibility of transportation cracking based on angular misalignment and the improper orientation of the long seam on the railcar. However, this hypothesis was ruled out when metallurgical analysis did not find fatigue striations that would be caused if the fracture surface had been exposed to the atmosphere.

Blade Energy Partners' RCFA of the MP 171 failure surface identified fatigue striations from atmospheric exposure from the pipe's transportation from Florida to the right-of-way in North Dakota.

Blade Energy Partners conducted an API 579 level 2 analysis of the critical crack size and rupture pressure. Anderson & Associates measured an initial crack size of 7.75 inches in length and a depth of 0.302 inches. Based on known and assumed parameters, including pipe properties and estimated crack size, the analysis estimated the failure pressure to be 1,305 psig, or a 4.2% difference from the actual failure pressure of 1,252 psig. The purpose of the API 579 level 2 analysis was to demonstrate a correlation between the calculated failure pressure via modeling and the actual failure pressure at the time of the rupture.

Blade Energy Partners calculated the fatigue crack growth rate based on the assumed crack size necessary to rupture the pipe after 15 years of operation with 546 MOP cycles. Utilizing material properties determined by Anderson & Associates, a 5% to 10% wall thickness transportation-related crack would have been necessary to cause the rupture within 15 years. MOP cycles alone would not have caused the rupture within 15 years; therefore, this confirmed that the pipe likely contained a crack induced by transportation-related fatigue before the pipeline began operation. The analysis also showed that considering an initial crack size penetrating approximately 10% of the wall thickness, coupled with the known number of MOP cycles, the expected calculated crack size during the 2020 (b)(4) [redacted] ILI would have approximately extended between 30% and 50% of the pipe's wall thickness. Based on the vendor ILI tool performance specification, the crack should have been detected, but it was not.

7. Findings and Contributing Factors

PHMSA has determined the rupture was caused by a manufacturing defect of angular misalignment and weld bead misalignment, which allowed transportation fatigue cracking to originate at the interior toe of the longitudinal seam. The initial transportation crack grew due to in-service pressure cycling, allowing environmental fatigue to occur until the remaining region could no longer support the hoop stress of the pipeline operation. The investigation highlighted the following findings and contributing factors:

- The pipe manufacturing inspection process failed to identify the angular misalignment and weld bead misalignment.
    - These features acted as stress concentrators that initiated a crack during pipe transportation that ultimately ruptured.
- The crack management program was ineffective in identifying the MP 171 feature that failed. The fatigue crack grew incrementally over 15 years of pipeline operation.

    - The Keystone Pipeline had higher fatigue induced operational cycles when the system went into service. While subsequent measures were taken to reduce the frequency of these operational cycles, such measures did not prevent the rupture that occurred at MP 171.
    - Ultrasonic crack detection technology was the primary method used to identify cracks in the Keystone Pipeline. With the history of cracking failures and the apparent inability to identify and remediate critical defects prior to failure, hydrostatic spike testing to 103%-105% percent of SMYS could have been used as a complementary assessment method to confirm the reliability of South Bow's crack management program and to provide confirmation of the pipeline's integrity. It was not.
- HIC was identified in the fracture surface. Hydrogen is known to reduce toughness.

A. Additional Photographs

B. NRC Report Nos. 1428025 & 1428221

C. Accident Report – Hazardous Liquid and Carbon Dioxide Pipeline Systems No. 20250112

D. Laboratory Analysis Metallurgical [CONFIDENTIAL] – Anderson & Associates, [June 13, 2025]

E. Contractor Failure Investigation Report [CONFIDENTIAL] – Blade Energy Partners, [September 15, 2025]

Appendix A: Additional Photographs

Figure 14. View of MP 171 failure site prior to cleanup. PHMSA AID Photo.

Figure 15. In Situ view of failure. PHMSA AID Photo.

Figure 16. Fully excavated failure during the drain down operation. PHMSA AID Photo.

Figure 17. Cutout and removal of section of pipe with feature. PHMSA AID Photo.

Figure 18. Segment with failure origin prepared for on-site non-destructive testing. PHMSA AID photo.

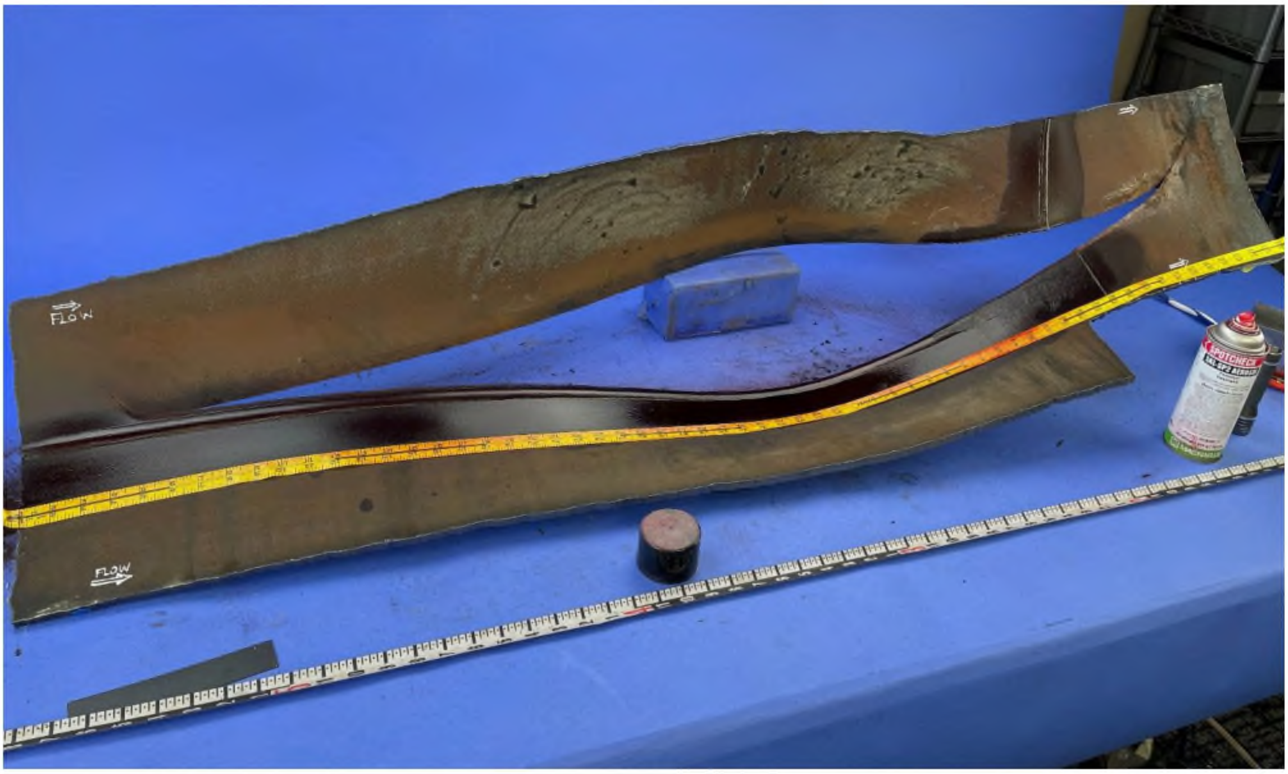


Figure 19. Failure origin feature cut-out for measurement and preparation for further lab analysis. PHMSA AID Photo.

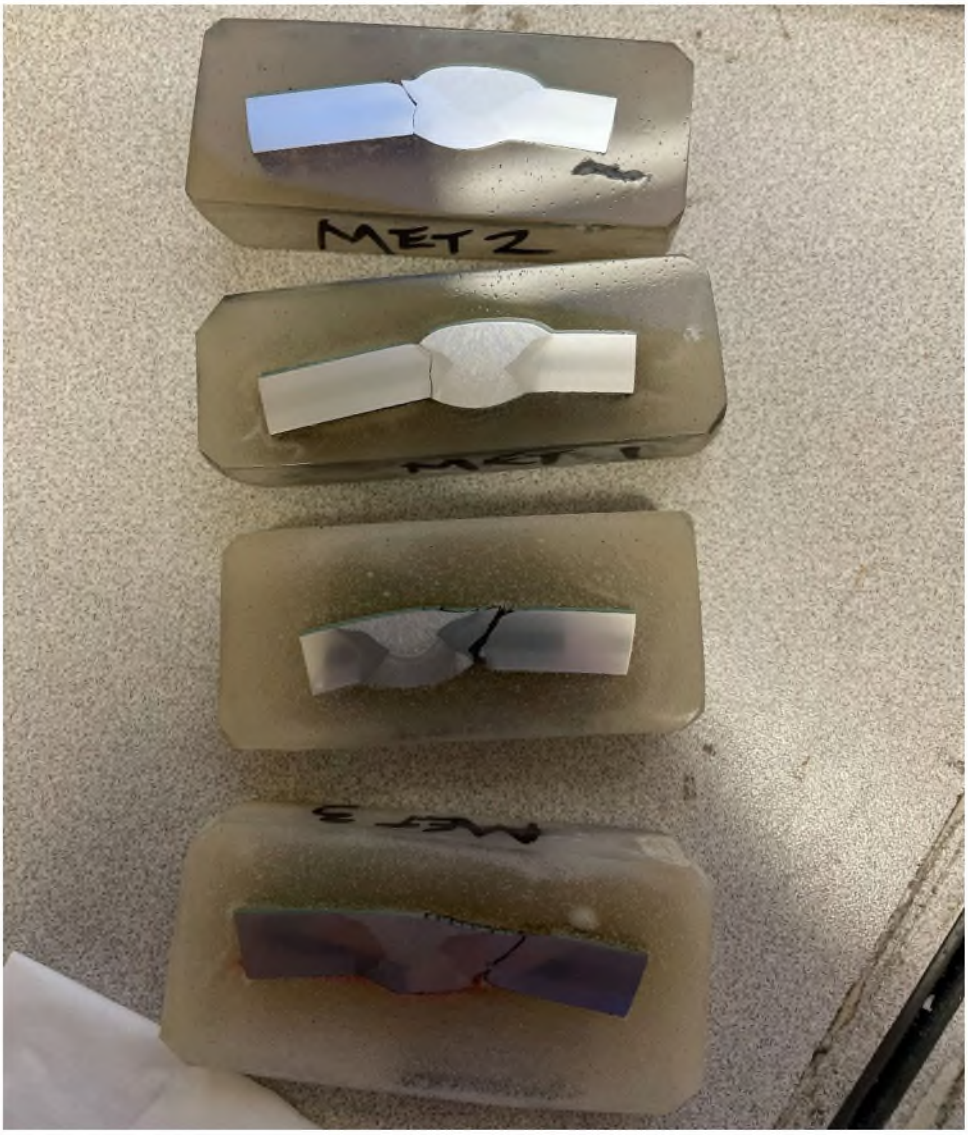


Figure 20. Cutout samples prepared by Anderson & Associates for further analysis. PHMSA AID Photo.