CAL FIRE - Office of the State Fire Marshal
Pipeline Safety Division

Pipeline Accident Report: Failure Investigation Report
Lead Investigator Name/Title: Thomas M. Williams IV, Pipeline Safety Engineer
Supervisor Name/Title: Linda Zigler, Supervising Pipeline Safety Engineer, Chuck MacDonald, Supervising Pipeline Safety Engineer
Activity Report #: 20160520TMW1
Report Date: April 6, 2017
Cal OES Control #: 16-2999
NRC Report #:1148267 and 1148268

OPERATOR, LOCATION, AND CONSEQUENCES

Date of Failure: May 20, 2016
Time Detected: 0035 hours, Pacific Standard Time (PST)
Operator Name: Shell Pipeline Company, LP
CSFM Billing Code: 330
CSFM Inspection Unit #: 0560A
CSFM Pipeline ID #: 0708 (North San Joaquin Valley - Tracy to Avon)
PHMSA Operator ID: 31174
Leak Location (City/County): Tracy/San Joaquin County
Latitude / Longitude Location: [redacted]
Pipeline: 20/24 inch "Tracy to Avon" intrastate pipeline
Type of Failure: Seam Failure - weld
Commodity Released: Crude Oil
Number of Barrels Released: 500 barrels
Number of Barrels Recovered: 400 barrels
Number of Fatalities: None
Number of Injuries: None
Waterways Impacted: None
Description of Property Damage: Contaminated Soil
Total Costs (Property Damage + Commodity Loss = Estimated Total): $4,540,000

Thom M. Williams IV 4/6/2017

Thomas M. Williams IV, Pipeline Safety Engineer

Chuck Mac Donald 4/6/2017

Chuck Mac Donald, Supervising Pipeline Safety Engineer

EXECUTIVE SUMMARY

At 0035 hours (PST) May 20, 2016, the Shell Pipeline Company LP (SPCLP) Control Center located in Houston, Texas detected a drop in the operating pressure on the North San Joaquin Valley (SJV) pipeline system. The Tracy Pump Station automatically shut down on low suction pressure and the SPCLP Houston Control Center Controller immediately shut down the entire SJV pipeline system and isolated the leaking section of pipe by closing the mainline line block valves at Westley, Tracy, Marsh Creek and Avon Pump Stations.

The failure occurred in an open field on the Tracy to Windmills Farm segment of the Tracy Pump Station to Avon Pump Station (CSFM Line ID #0708) pipeline approximately ¾ of a mile north of the Tracy Pump Station located near West Patterson Pass Road and Interstate 580 in Alameda County, California. No waterways were impacted, and no fire, injuries or death occurred because of the spill.

A 79.8-foot section of pipe containing the rupture was cut out and replaced with a new section of pre-hydrostatically pressure tested pipe. A 26-foot long section of pipe containing the rupture was transferred via chain of custody to Det Norske Veritas, Inc. (DNV-GL), a testing laboratory in Dublin, Ohio, for metallurgical examination. A review of the metallurgical examination results in the DNV-GL Laboratory Report Number OAPUS311MPHB (PP158491) issued on November 7, 2016, revealed the pipe ruptured at a fatigue crack that initiated at the toe of the Double Submerged Arc Weld (DSAW) longitudinal seam weld on the inside surface of the pipe. The release occurred on pipe that was originally purchased by Texaco Trading & Transportation Inc. from Columbia Gas and installed by Texaco in 1989.

After repairs were made, the entire pipeline was hydrostatically pressure tested, and the pipeline was reactivated on July 19, 2016.

DESCRIPTION OF THE PIPELINE SYSTEM

The North SJV pipeline system is part of SPCLP's common carrier pipeline system that delivers, heavy, light and blended crude oil from the San Joaquin Valley to San Francisco Bay area refineries. The entire system is approximately 177 miles in length and starts at the SPCLP Coalinga Pump Station and terminates at the SPCLP Martinez Refinery. The entire system was originally constructed by Texaco Trading & Transportation Inc. This system is comprised of the following seven pipeline segments:

- CSFM Line ID #0704 is a 24-inch pipeline originally constructed in 1967 that transports crude oil 6.14 miles from Shell Coalinga Tank Farm to Mack Hill Valve Station.

- CSFM Line ID #0401 is a 20-inch pipeline originally constructed in 1967 that transports crude oil 46.44 miles from Mack Hill Valve Station to Panoche Pump Station.

- CSFM Line ID #0705 is a 20-inch pipeline originally constructed in 1968 that transports crude oil 34.6 miles from Panoche Pump Station to Butts Road Valve Station.

- CSFM Line ID #0707 is a 24-inch pipeline originally constructed in 1967 that transports crude oil 7.07 miles from Butts Road Valve Station to Gustine Pump Station.

- CSFM Line ID #0796 is a 20-inch pipeline originally constructed in 1967 that transports crude oil 42.17 miles from Gustine Pump Station to Tracy Pump Station.

- CSFM Line ID #0708 is a 20/24-inch pipeline originally constructed in 1968 that transports crude oil 38.12 miles from Tracy Pump Station to Avon Pump Station.

- CSFM Line ID #0709 is a 20-inch pipeline originally constructed in 1968 that transports crude oil 2.98 miles from Avon Pump Station to Martinez Refinery.

According to representatives of SPCLP, 12.55 miles of the following segments in the North SJV system have pipe that was purchased from Columbia Gas by Texaco Trading and Transportation. This pipe was manufactured in Houston, Texas by Armco Steel in 1982 and was shipped from Columbia Gas in the northeast United States to Coalinga, California in 1988.

- CSFM Line ID # 0708 – 3.05 miles of the total 38.12-mile long pipeline.

- CSFM Line ID # 0704 – 3.4 miles of the total 6.14-mile long pipeline.

- CSFM Line ID # 0707 – 6.1 miles of the total 7.07-mile long pipeline.

DESCRIPTION OF PIPELINE FAILURE AND INITIAL RESPONSE

A sudden pressure loss was detected by the SPCLP Control Center at 0035 hours (PST) on May 20, 2016. The Tracy Pump Station automatically shut down on low suction pressure and the Houston Controller immediately shutdown the entire North SJV pipeline system. The Controller then isolated the leaking section of pipeline by closing the following motor operated valves (MOV): Westley Valve #001, Tracy Valve #008, Marsh Creek Valves #001 and #008, North 20/24-inch Main Line Block Valves #158 and #169, and the Avon #1 Block Valve. These valves were closed in their pre-planned sequence to prevent any pressure surges. Calculated pressure at the release location at the time of failure was 694 psi. SPCLP notified both the California Office of Emergency Services (Cal OES) and the National Response Center (NRC). CAL FIRE – Office of the State Fire Marshal (OSFM) responded to the release after being notified by Cal OES. The pipeline failure was in a rural area with dry grass on rolling hills. Vacuum trucks were brought in to recover the spilled oil.

At the time of the failure, the pipeline was transporting SJV heavy crude oil. The flowrate was 6,126 barrels per hour (BPH) and the discharge pressure was 694 psi at the Tracy Pump Station. The maximum operating pressure (MOP) was 936 psi.

Representatives of SPCLP and the Oil Spill Response Organizations – Patriot Environmental Services and Ponder Environmental Services – excavated, exposed the pipeline, and recovered the spilled oil. Crude oil had sprayed over an area of approximately 100 feet long by 100 feet wide and had partially soaked into the soil. According to the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) Accident Report Form 7000-1 submitted by SPCLP, approximately 500 barrels of crude oil was released and 400 barrels were recovered.

Excavation of the failed pipe showed that a rupture occurred along the length of the longitudinal seam at the 3:26 o'clock position. The rupture was approximately 3.77 feet in length by 4.5 inches in width, defined as a fish mouth failure. The seam failure was located 14.17-feet and 17.94-feet respectively from the upstream girth weld.

The specifications of the failed pipe section are:

Year Manufactured: 1982
Manufacturer: Armco Steel
Pipe Diameter: 24-inch Outside Diameter
Wall Thickness: 0.260-inch
Specified Minimum Yield Strength: X-60 (60,000 psi)
Pipe Specification: API-5L
Pipe Seam: Double Submerged Arc Weld (DSAW)
Type of Coating: Polyolefin
Depth of Cover: 84-inches

REMOVAL OF DEFECTIVE PIPE SECTION

DNV-GL was contracted by SPCLP to perform the metallurgical examination of the failed pipe. At approximately 0300 hours (PST) on May 22, 2016, a 79-foot 8-inch long section of the 24-inch pipe containing the seam failure was cut out and removed. Pipeline Safety Engineers from OSFM were on site to monitor the activities. An estimated 29-foot pipe section that contained the 26.4-foot field joint was wrapped in plastic, mounted and secured on pallets, and stored in a guarded area until it could be transported to the DNV-GL Laboratory in Dublin, Ohio. OSFM staff witnessed the chain of custody process of the failed pipe section from SPCLP to a third-party shipping contractor, Byars Trucking. SPCLP handled the pipe section according to SPCLP's "Handling Instructions for Retrieval of Pipe Section(s) Containing Defects SJV 24-inch Crude Line" procedure, dated September 17, 2015. Representatives of SPCLP followed their Chain of Custody procedures for storing and shipping of the pipe.

PIPELINE REPAIRS

On May 22, 2016, a 79-foot 8-inch long section of pre-hydrostatically tested pipe (CSFM Test ID #16-04897) was installed by Doty Brothers Construction Company of Norwalk, California. The hydrostatic pressure test was conducted by Contra Costa Inspection (CCI), an OSFM approved hydrostatic testing firm.

The specifications for the replacement pipe are:

Manufacturer: CSI Tubular Products, Inc., Fontana, California
Pipe Diameter: 24-inch Outside Diameter
Wall Thickness: 0.375-inch
Specified Minimum Yield Strength: X-65 (65,000 psi)
Pipe Specifications: API-5L
Pipe Seam: Electric Resistance Weld (ERW)

Prior to Doty Brothers' personnel performing the repairs of the pipeline, OSFM Pipeline Safety Engineers verified the Operator Qualification (OQ) records of the following:

- SPCLP Lead Inspector
- Doty Brothers welders
- Applus Non-Destructive Testing Technician.

OSFM Pipeline Safety Engineers observed the welding of the replaced section of 24-inch pipe. The pipeline tie-in welds were non-destructively tested by x-ray and a phased array ultrasonic test, performed by Applus. After the welds were successfully tested, the tie-in welds were coated with a 3-layer epoxy and were wrapped with Polyken Liquid Adhesive and Polyken tape coating.

On May 23, 2016, after consultation with the OSFM, the North SJV pipeline system was temporarily returned to service at a 20% reduced pressure from 694 psi to 555 psi to displace the heavy crude oil remaining in the line to prevent the crude oil from solidifying in the pipeline. The pipeline temporarily operated at 555 psi, which is a 20% reduced pressure from the 694 psi pressure at the time of the failure. The pipeline system was shut down after the crude oil was displaced. Prior to reactivation of the North SJV pipeline system, SPCLP successfully hydrostatic tested the following segments of the pipeline system that contain the suspected Columbia Gas pipe.

- CSFM Line ID #0708 was hydrostatic tested on June 9, 2016 by Contra Costa Inspection (CSFM Test ID # 16-05004). An 8-hour test was conducted and the minimum test pressure obtained was 1,070 psi.
- CSFM Line ID #0704 was hydrostatic tested on June 17, 2016 by Contra Costa Inspection (CSFM Test ID # 16-05015). An 8-hour test was conducted and the minimum test pressure obtained was 1,070 psi.
- CSFM Line ID #0707 was hydrostatic tested on June 30, 2016 by Contra Costa Inspection (CSFM Test ID# 16-05019). An 8-hour test was conducted and the minimum test pressure obtained was 1,070 psi.

INVESTIGATION DETAILS

The pipeline (CSFM Line ID #0708) experienced the following two previous releases due to seam failure.

- **June 6, 1998: (Equilon Pipeline Company)** 300 barrels of crude oil was released near Midway Road and I-580. Pipe failed approximately one mile downstream of Tracy Pump Station due to a pipe seam defect. An estimated 40 feet of pipe was replaced (Cal OES Control # 98-0606A).

- **September 16, 2015: (Shell Pipeline Company, LP)** 900 barrels of crude oil was released at mile post 137, near Tracy, California, on the Coalinga to Avon pipeline. Pipeline ruptured at a pre-existing fatigue crack initiated from small corrosion pits along the internal surface at the toe of the longitudinal seam weld. (Cal OES Control # 15-5483 & NRC #1128732).

A review of the September 16, 2015 pipeline rupture investigation report revealed that on August 6, 2015, TD Williamson (TDW) performed a Magnetic Flux Leak (MFL) and deformation In-Line Inspection (ILI) survey on the pipeline (CSFM Line ID# 0708). The preliminary TDW ILI report issued on September 2, 2015 indicated no immediate conditions were found, as defined by Code of Federal Regulations, Title 49, Part 195.452. Fourteen days later, the pipeline ruptured approximately 1,800 feet downstream of the Tracy Pump Station. The final TDW ILI report was received by SPCLP on October 14, 2015 and did not identify any metal loss or deformation anomalies at the leak location.

Following the September 16, 2015 release, SPCLP contracted with DNV-GL to perform a metallurgical analysis on the failed section of the pipe. This analysis determined that the pipe section ruptured at a pre-existing fatigue crack on the longitudinal seam. The line was repaired and resumed operation on September 21, 2015. SPCLP initiated a voluntary 20% reduced operating pressure to 724 psi from the previous 905 psi while they investigated the pipeline for similar fatigue crack features. SPCLP decided to use a Rosen Ultrasonic Crack Detection Tool (UT-C) and a Circumferential Magnetic Flux Leak Tool (MFL-C) on the 24-inch pipe in the North SJV pipeline system. The Rosen MFL-C tool was utilized on December 3, 2015 and the UT-C survey was utilized on December 4, 2015.

A preliminary Rosen MFL-C ILI report on January 14, 2016 identified two metal loss anomalies on the Butts Road Valve Station to Gustine Pump Station pipeline (CSFM Line ID # 0707). Type B full encirclement sleeves were used to repair these anomalies. On March 7, 2016, Rosen issued the final MFL-C ILI report that identified an additional 19 anomalies within a 42-foot section of pipe on the Butts Road Pump Station to Gustine Pump Station pipeline (CSFM Line ID # 0707). These anomalies were also repaired using Type B full encirclement sleeves.

On April 11, 2016, the preliminary Rosen UT-C ILI report was received by SPCLP. In the report, five anomalies were identified. Two of these anomalies were on the Tracy Pump Station to Avon Pump Station pipeline (CSFM Line ID # 0708). These anomalies were excavated and no crack indications were found. The anomalies were recoated and the line was backfilled. Two anomalies were identified on the Coalinga to Mack Hill Valve Station pipeline (CSFM Line ID # 0704) requiring an excavation dig. The first anomaly revealed a crack like indication that was repaired with a Type B full encirclement sleeve. The second anomaly identified a metal loss feature and it was repaired and recoated. The last anomaly identified by Rosen was a crack like anomaly on the Butts Road Valve Station to Gustine Pump Station pipeline (CSFM Line ID # 0707). However, upon examination no dents or cracks were found and it was repaired with a Type B full encirclement sleeve.

On May 2, 2016, the final Rosen UT-C ILI report was provided to SPCLP that identified two anomalies that required excavation. One anomaly was a 3-inch flat spot and the other anomaly was a seam weld repair that was done at the pipe mill. Both anomalies were repaired and recoated. Based on the Rosen MFL-C and UT-C results, SPCLP decided to remove the pressure reduction on the 24-inch segments of the North SJV pipeline system. The 20% operating pressure reduction was removed on May 17, 2016 and the pipeline was operating at the normal operating pressure. Three days later, on May 20, 2016, the pipeline (CSFM Line ID# 0708) failed approximately 4,000 feet downstream of the Tracy Pump Station.

Immediately following the release, SPCLP and the OSFM requested that Rosen review and re-evaluate the data from the December 3 and 4, 2015 Rosen ILI surveys. Rosen's review of the ILI data concluded that the survey data did not report any features at the location of the failure.

SPCLP contracted with Kinder Morgan Energy Partners to perform a Kinder Morgan Assessment Protocol (KMAP) review of the Rosen MFL-C ILI data at the failure location. The KMAP is a Kinder Morgan proprietary analytical process that is designed to search for flaws in longitudinal seam welds. The result of the KMAP confirmed that there were no reportable features in the pipe section that failed from the data they received.

SPCLP conducted an internal Root Cause Analysis (RCA) on the May 20, 2016 rupture. According to the RCA, SPCLP found that Rosen's ILI software used to evaluate the Rosen UT-C ILI survey did identify a crack like feature in the longitudinal seam at the failure location. The RCA found that the Rosen ILI software identified the crack as 7.594 inches long and 0.150 inches deep (57.7% of 0.260-inch nominal wall thickness) at odometer reading 4073.718 (rupture location). During the manual review by Rosen analysts, "an incorrect amplitude was selected" and an anomaly depth was calculated at <0.08-inch. Rosen believed that the reporting threshold was 0.08-inch. The Rosen analyst then called the anomaly at 4073.718 (rupture location) as being 0.013-inch. SPCLP's RCA indicates that the Rosen report did not show an anomaly at the rupture location due to this error. As a result, SPLCP resumed operations with normal operating pressure on May 17, 2016.

OSFM contacted Rosen to confirm the data provided in the RCA, however, Rosen only confirmed that they did not report the crack-like anomaly at the position in the failed pipe section.

SPCLP also contracted with DNV-GL to perform a metallurgical analysis on the failed pipe. DNV-GL issued the final report of the metallurgical analysis on November 7, 2016 (Test Report Number OAPUS311MPHB (PP158491)). The examinations DNV-GL performed to determine the metallurgical cause of the failure and to identify any contributing factors included; a visual and photographic examination, dimensional measurements, magnetic particle examination, light microscopy and scanning electron microscopy of the fracture surfaces, cross sections examination, energy dispersive spectroscopy, tensile tests and Charpy V-notch tests, chemical analysis of the steel, and failure pressure calculations.

A review of the final report of metallurgical examination conducted by DNV-GL revealed that:

- The pipe joint ruptured at a fatigue crack initiated at the toe of the DSAW longitudinal seam weld on the inside surface of the pipe.
- A likely contributing factor was a peaked geometry of the failed pipe joint at the seam weld that introduced a bending stress.
- A contributing factor was corrosion micro-pits on the internal diameter surface that provided initiation sites.
- A contributing factor of aggressive pressure cycling of the pipeline.
- Possible environmental effect on crack growth.
- Another possible contributing factor that could not be ruled out was transit fatigue during transportation of the pipe.

DNV-GL conducted the metallurgical examination in accordance with industry accepted standards and used the following American Society for Testing and Materials (ASTM) standards:

- ASTM E7 – Standard Terminology Relating to Metallography
- ASTM E3 – Standard Methods of Preparation of Metallographic Specimens
- ASTM E8 – Test Methods for Tension Testing of Metallic Materials
- ASTM E23 – Standard Test Methods for Notched Bar Impact Testing of Metallic Materials
- ASTM A751 -Standard Test Methods, Practices and Terminology for Chemical Analysis of Steel Products.

According to the DNV-GL final report, there was no evidence of external corrosion found. Tensile testing indicated that the pipe met the tensile requirements for American Petroleum Institute (API) 5L Grade X60 pipe. The composition of the base metal of the failed joint and the joints up stream and down stream met the requirements of API-5L Grade X60 pipe.

It should be noted that the DNV-GL report also indicated that the fatigue crack likely occurred while the pipeline was in service, and that transit fatigue during the pipe transportation cannot be ruled out. According to SPLCP transportation records, the pipe was manufactured by Armco Steel in Houston, Texas for Columbia Gas and was shipped to the northeast United States in 1982. In 1988, Texaco purchased the pipe from Columbia Gas and transported it to Coalinga, California for installation and the records for this shipment cannot be located.

American Petroleum Institute Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1) is used to assure that pipe is properly loaded and transported to avoid transit fatigue. API RP 5L1 also states that pipe with a diameter to wall thickness ratio greater than 50 is susceptible to transit fatigue. The failed pipe had a ratio of 92 (24-inch/0.260-inch wall thickness).

INVESTIGATION FINDINGS

- The OSFM concluded that the primary cause of the May 20, 2016 release was a fatigue crack that initiated at the toe of the longitudinal seam weld on the inside surface of the pipe (CSFM Line ID #0708) that developed and grew through continuous pressure cycling.
- The May 2, 2016, Rosen UT-C ILI report failed to identify the crack like feature in the longitudinal seam of the pipe.
- It is possible that transit fatigue may have occurred during transportation of the pipe in 1988.

RECOMMENDATIONS

1. Effective immediately, the Tracy Pump Station to Avon Pump Station pipeline (CSFM Line ID# 0708) shall be placed on the State Fire Marshal's list of higher risk pipelines as required by Government Code Section 51013.5 (f)(1). SPCLP will be required to either perform in-line inspections or hydrostatic tests every two years. The pipeline will be removed from this list after May 20, 2021, if there are no more leaks due to corrosion or manufacturing defects during this time.

2. SPCLP shall replace the entire sections of the pipeline that contain "Columbia Pipe". These sections are the 3.05 miles of the total 38.12-mile long pipeline from Tracy Pump Station to Avon Pump Station (CSFM Line ID # 0708), 3.4 miles of the 6.14-mile long pipeline from Coalinga Pump Station to Mack Hill Valve Station (CSFM Line ID # 0704), and 6.1 miles of the 7.07-mile long pipeline from Butts Road Valve Station to Gustine Pump Station (CSFM Line ID # 0707).

3. SPCLP shall require all ILI vendors to immediately notify SPCLP personnel of any raw data that is excluded from all future reports. SPCLP should also review their process for conducting crack detection surveys for all seam types of pipe – DSAW, ERW, etc.

4. SPCLP shall review and evaluate their pipelines that undergo aggressive pressure cycling to determine if additional crack detection surveys should be conducted on these pipelines and to determine if pressure cycling can be minimized.

5. The OSFM Pipeline Safety Division shall conduct a comprehensive and in-depth Headquarters review of SPCLP's Integrity Management Program. This inspection will be conducted the week of September 25, 2017.

Photo Log of Spill - Operator: Shell Pipeline Company L.P. – Tracy Windmill Farms Spill Date: May 20, 2016.

Photograph #1

<u>Description of Photograph</u>: Photo taken by Pipeline Safety Engineer Thomas Williams on the morning of May 20, 2016 This is an overview of the San Joaquin Valley 20/24" Heavy Crude Oil (CSFM #0708) spill site (Tracy Windmill Farms looking South.)

Photograph #2

<u>Description of Photograph</u>: Photo taken by Pipeline Safety Engineer Thomas Williams on May 20, 2016. This is another overview of the spill on The San Joaquin Valley 20/24" Heavy Crude Oil (CSFM #0708) Tracy Windmill Farms looking North.

	**Photograph #3** <u>Description of Photograph</u>: Photo taken by Pipeline Safety Engineer Thomas Williams on the morning of May 21, 2016. This is a view of the rupture on The San Joaquin Valley 20/24" Heavy Crude Oil (CSFM #0708)
	**Photograph #4** <u>Description of Photograph</u>: This is a picture of the CSFM Pre-hydrotested pipe information Photo taken by Pipeline Safety Engineer Thomas Williams on the morning of May 21, 2016.

	**Photograph #5** Description of Photograph: Photo taken by Pipeline Safety Engineer Thomas Williams on May 22, 2016. This is a photo of Doty Brothers Construction Company cutting out the failed section of pipe to send to Lab.
	**Photograph #6** Description of Photograph: Photo taken by Pipeline Safety Engineer Thomas Williams on the early morning of May 22, 2016. This is a photo of Doty Brothers Construction Company weld the new section of pipe.

Photograph #6

Description of Photograph:
Photo taken by Pipeline Safety Engineer Thomas Williams on the early morning of May 22, 2016. This is a photo of ApplusRTD technicians shooting x-rays on the welds on CSFM #0708

Photograph #6

Description of Photograph:
Photo taken by Pipeline Safety Engineer Thomas Williams on May 22, 2016. This is a photo of ApplusRTD technicians using Phased Array

Governor's Office Emergency Services

Hazardous Materials Spill Report

DATE: 05/20/2016 TIME: 0221	RECEIVED BY:	CONTROL#: Cal OES - **16-2999** NRC -

1.a. PERSON NOTIFYING Cal OES:

1. NAME:	2. AGENCY:	3. PHONE#:	4. Ext:	5. PAG/CELL:
	Shell Pipeline			

1.b. PERSON REPORTING SPILL (If different from above):

1. NAME:	2. AGENCY:	3. PHONE#:	4. Ext:	5. PAG/CELL:

2. SUBSTANCE TYPE:

2. a. SUBSTANCE:	b.QTY:>=<*Amount*	*Measure*	c. TYPE:	d. OTHER:	e. PIPELINE	f. VESSEL >= 300 Tons
1. Crude Oil =	Unknown	Bbl.(s)	PETROLEUM		Yes	No
2. =					No	No
3. =					No	No

g. DESCRIPTION: POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.

h. CONTAINED:	i. WATER INVOLVED:	j. WATERWAY:	k. DRINKING WATER IMPACTED
Unknown	Unknown		Unknown
l. KNOWN IMPACT	Unknown		

3. a. INCIDENT LOCATION: Between Tracy and Martinez, closer to Tracy. Station markers are Tracy station and Marsh Creek.

b. CITY:	c. COUNTY:	d. ZIP:	
Tracy	San Joaquin County		SAN JOAQUIN VALLEY UNIFIED APCD

4. INCIDENT DESCRIPTION:

a. DATE:	b. TIME *(Military)*:	c. SITE:	d. REPORTED CAUSE
05/20/2016	0205	Pipe Line	Unknown
e. INJURIES	**f. FATALITY**	**g. EVACUATION**	**h. CLEANUP BY:**
No	No	No	Unknown

6. NOTIFICATION INFORMATION:

a. ON SCENE: **b. OTHER ON SCENE:** **c. OTHER NOTIFIED:**

d. ADMIN. AGENCY: San Joaquin County Environmental Health

e. SEC. AGENCY:

f. ADDITIONAL COUNTY: Alameda County, Contra Costa County

g. ADMIN. AGENCY: Alameda County Environmental Health, Contra Costa County Health Services Department

h. NOTIFICATION LIST:

DOG Unit: 6

RWQCB Unit: 5B

AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

Photo Attachment:	

********* **Control No: 16-2999** *********

Created by: Warning Center on: 05/20/2016 02:21:27 AM Last Modified by: Warning Center on: 05/20/2016 02:49:58 AM

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Governor's Office of Emergency Services

Hazardous Material Spill Update

CONTROL#: 16-2999 NRC# 1148267

NOTIFY DATE/TIME:	RECEIVED BY:	CITY/OP. AREA:
05/20/2016 / 0221	OCCURENCE DATE/TIME: 05/20/2016/0205	Tracy/San Joaquin County SAN JOAQUIN VALLEY UNIFIED APCD

1.a. PERSON NOTIFYING Cal OES:

AGENCY: Shell Pipeline	

1.b. PERSON REPORTING SPILL (If different from above):

AGENCY:	

SUBSTANCE TYPE:

a. SUBSTANCE:	b. QTY: *Amount*	*Measure*	c. TYPE:	d. OTHER:	e. PIPELINE	f. VESSEL >= 300 Tons
1.Crude Oil	Unknown	Bbl.(s)	PETROLEUM		Yes	No
2.					No	No
3.					No	No

Orignal Description:POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.

PERSON NOTIFYING Cal OES OF SPILL UPDATE:

NAME:	AGENCY:	PHONE#:	Ext:	PAG/CELL:
	NRC			

UPDATE QUANTITY *Amount*	*Measure*
1.	Bbl.(s)
2.	
3.	
4.	

UPDATE KNOWN IMPACT:	
UPDATE CAUSE:	

SITUATION UPDATE:

Per the NRC Report: "THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE. BELOW GROUND PIPELINE. REMEDIAL ACTIONS *

CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED."

FAX NOTIFICATION LIST:
AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

ADMINISTERING AGENCY:	San Joaquin County Environmental Health
SECONDARY AGENCY:	
ADDITIONAL COUNTIES:	Alameda County, Contra Costa County
ADDITIONAL ADMIN. AGENCY:	Alameda County Environmental Health, Contra Costa County Health Services Department
OTHER NOTIFIED:	
RWQCB Unit:	5B

CONFIRMATION REQUEST:

FAX NOTIFICATION LIST:

ADMINISTERING AGENCY:

ADDITIONAL ADMIN. AGENCY:

SECONDARY AGENCY:

ADDITIONAL COUNTIES:

DOG Unit:

RWQCB Unit:

Created by: Warning Center on: 05/20/2016 03:04:37 AM Last Modified by: Warning Center on: 05/20/2016 03:11:09 AM

************* End of Form *************

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Governor's Office of Emergency Services
Hazardous Material Spill Update

CONTROL#: 16-2999 NRC#

NOTIFY DATE/TIME:	RECEIVED BY:	CITY/OP. AREA:
05/20/2016 / 0221	OCCURENCE DATE/TIME: 05/20/2016/0205	Tracy/San Joaquin County SAN JOAQUIN VALLEY UNIFIED APCD

1.a. PERSON NOTIFYING Cal OES:

AGENCY: Shell Pipeline	

1.b. PERSON REPORTING SPILL (If different from above):

AGENCY:	

SUBSTANCE TYPE:

a. SUBSTANCE:	b. QTY: *Amount*	*Measure*	c. TYPE:	d. OTHER:	e. PIPELINE	f. VESSEL >= 300 Tons
1.Crude Oil	Unknown	Bbl.(s)	PETROLEUM		Yes	No
2.					No	No
3.					No	No

Orignal Description:POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.
Update(s): 05/20/2016 03:04:37 AM - Per the NRC Report: "THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE. BELOW GROUND PIPELINE. REMEDIAL ACTIONS * CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED."
; 05/20/2016 04:03:39 AM - RP States: No waterways impacted. Location: .75 miles NNW of West Patterson Past Road and I 580 in San Joaquin County. 500 barrels is equivalent to 21,000 gallons of crude oil released.

PERSON NOTIFYING Cal OES OF SPILL UPDATE:

NAME:	AGENCY:	PHONE#:	Ext:	PAG/CELL:
	Shell Pipeline			

UPDATE QUANTITY *Amount*	*Measure*
1. 500	Bbl.(s)
2.	
3.	

4.

UPDATE KNOWN IMPACT:	
UPDATE CAUSE:	

SITUATION UPDATE:

RP States: No waterways impacted. Location: .75 miles NNW of West Patterson Past Road and I 580 in San Joaquin County. 500 barrels is equivalent to 21,000 gallons of crude oil released.

FAX NOTIFICATION LIST:

AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

ADMINISTERING AGENCY:	San Joaquin County Environmental Health
SECONDARY AGENCY:	
ADDITIONAL COUNTIES:	Alameda County, Contra Costa County
ADDITIONAL ADMIN. AGENCY:	Alameda County Environmental Health, Contra Costa County Health Services Department
OTHER NOTIFIED:	
RWQCB Unit:	5B

CONFIRMATION REQUEST: **Please confirm receipt via email or call 916-845-8911.**

FAX NOTIFICATION LIST:

ADMINISTERING AGENCY:

ADDITIONAL ADMIN. AGENCY:

SECONDARY AGENCY:

ADDITIONAL COUNTIES:

DOG Unit:

RWQCB Unit:

Created by: Warning Center on: 05/20/2016 04:03:39 AM Last Modified by: Warning Center on: 05/20/2016 04:24:40 AM

************* End of Form *************

ATTACHMENT #1

PrevDoc | NextDoc

Governor's Office of Emergency Services
Hazardous Material Spill Update

CONTROL#: 16-2999 NRC#

NOTIFY DATE/TIME:	RECEIVED BY:	CITY/OP. AREA:
05/20/2016 / 0221	OCCURENCE DATE/TIME: 05/20/2016/0205	Tracy/San Joaquin County SAN JOAQUIN VALLEY UNIFIED APCD

1.a. PERSON NOTIFYING Cal OES:

AGENCY: Shell Pipeline	

1.b. PERSON REPORTING SPILL (If different from above):

AGENCY:	

SUBSTANCE TYPE:

a. SUBSTANCE:	b. QTY: Amount	Measure	c. TYPE:	d. OTHER:	e. PIPELINE	f. VESSEL >= 300 Tons
1. Crude Oil	Unknown	Bbl.(s)	PETROLEUM		Yes	No
2.					No	No
3.					No	No

Orignal Description: POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.

Update(s): 05/20/2016 03:04:37 AM - Per the NRC Report: "THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE. BELOW GROUND PIPELINE. REMEDIAL ACTIONS * CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED."

; 05/20/2016 04:03:39 AM - RP States: No waterways impacted. Location: .75 miles NNW of West Patterson Past Road and I 580 in San Joaquin County. 500 barrels is equivalent to 21,000 gallons of crude oil released.

; 05/20/2016 04:24:53 AM - Per NRC Report"ACCORDING TO THE REPORTING PARTY THERE IS A DISCHARGE OF 500 BARRELS OF CRUDE OIL ONTO THE GROUND. NO WATERWAYS IMPACTED. REMEDIAL ACTIONS * CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED. ACCORDING TO THE REPORTING PARTY THERE IS A DISCHARGE OF 500 BARRELS OF CRUDE OIL ONTO THE GROUND. NO WATERWAYS IMPACTED. THE NEW NRC REPORT NUMBER IS 1148268.

; 05/21/2016 02:40:43 PM - Per RP the spill is in Alameda County

PERSON NOTIFYING Cal OES OF SPILL UPDATE:

NAME:	AGENCY:	PHONE#:	Ext:	PAG/CELL:
	Shell Pipeline			

Measure

UPDATE
QUANTITY

Amount

1. Bbl.(s)
2.
3.
4.

UPDATE KNOWN IMPACT:	
UPDATE CAUSE:	

SITUATION UPDATE:

Per RP the spill is in Alameda County

FAX NOTIFICATION LIST:

AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

ADMINISTERING AGENCY: San Joaquin County Environmental Health

SECONDARY AGENCY:

ADDITIONAL COUNTIES: Alameda County, Contra Costa County

ADDITIONAL ADMIN. AGENCY: Alameda County Environmental Health, Contra Costa County Health Services Department

OTHER NOTIFIED:

RWQCB Unit: 5B

CONFIRMATION REQUEST:

FAX NOTIFICATION LIST:

ADMINISTERING AGENCY:

ADDITIONAL ADMIN. AGENCY:

SECONDARY AGENCY:

ADDITIONAL COUNTIES:

DOG Unit:

RWQCB Unit:

Created by: Warning Center on: 05/21/2016 02:40:43 PM Last Modified by: Warning Center on: 05/21/2016 02:43:54 PM

* * * * * * * * * * * * * End of Form * * * * * * * * * * * * *

PrevDoc | NextDoc

Governor's Office of Emergency Services
Hazardous Material Spill Update

CONTROL#: 16-2999 NRC#

NOTIFY DATE/TIME:	RECEIVED BY:	CITY/OP. AREA:
05/20/2016 / 0221	OCCURENCE DATE/TIME: 05/20/2016/0205	Tracy/San Joaquin County SAN JOAQUIN VALLEY UNIFIED APCD

1.a. PERSON NOTIFYING Cal OES:

AGENCY: Shell Pipeline	

1.b. PERSON REPORTING SPILL (If different from above):

AGENCY:	

SUBSTANCE TYPE:

a. SUBSTANCE:	b. QTY: *Measure Amount*	c. TYPE:	d. OTHER:	e. PIPELINE	f. VESSEL >= 300 Tons
1.Crude Oil	Unknown Bbl.(s)	PETROLEUM		Yes	No
2.				No	No
3.				No	No

Orignal Description:POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.

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; 05/21/2016 02:40:43 PM - Per RP the spill is in Alameda County

PERSON NOTIFYING Cal OES OF SPILL UPDATE:

NAME:	AGENCY:	PHONE#:	Ext:	PAG/CELL:
	Shell Pipeline			

UPDATE QUANTITY

Amount	*Measure*
1.	Bbl.(s)
2.	
3.	
4.	

UPDATE KNOWN IMPACT:	
UPDATE CAUSE:	

SITUATION UPDATE:

Per RP the spill is in Alameda County

FAX NOTIFICATION LIST:

AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

ADMINISTERING AGENCY: San Joaquin County Environmental Health

SECONDARY AGENCY:

ADDITIONAL COUNTIES: Alameda County, Contra Costa County

ADDITIONAL ADMIN. AGENCY: Alameda County Environmental Health, Contra Costa County Health Services Department

OTHER NOTIFIED:

RWQCB Unit: 5B

CONFIRMATION REQUEST:

FAX NOTIFICATION LIST:

ADMINISTERING AGENCY:

ADDITIONAL ADMIN. AGENCY:

SECONDARY AGENCY:

ADDITIONAL COUNTIES:

DOG Unit:

RWQCB Unit:

Created by: Warning Center on: 05/21/2016 02:40:43 PM Last Modified by: Warning Center on: 05/21/2016 02:43:54 PM

************* End of Form *************

FW: NRC#1148267: Pipeline - Tracy, CA (55 miles E of San Francisco, CA), unknown amount of crude oil spill

Katchmar, Peter (PHMSA) [Peter.Katchmar@dot.gov]
Sent: Wednesday, December 21, 2016 8:37 AM
To: MacDonald, Chuck@CALFIRE

Thank you,

Peter Katchmar

Western Region, PHMSA
Accident Coordinator
[redacted]

From: Katchmar, Peter (PHMSA)
Sent: Friday, May 20, 2016 4:33 AM
To: State-CSFM-Bob Gorham <Bob.Gorham@fire.ca.gov>; State-CSFM-Doug Allen <Doug.Allen@fire.ca.gov>; State-CSFM-Linda Zigler <Linda.Zigler@fire.ca.gov>
Cc: PHMSA PHP500 Response <PHMSAPHP500Response@dot.gov>
Subject: FW: NRC#1148267: Pipeline - Tracy, CA (55 miles E of San Francisco, CA), unknown amount of crude oil spill

Please provide a report on this event when possible.

Thank you,
Peter J. Katchmar
[redacted]

Sent with Good (www.good.com)

From: CMC-01 (OST)
Sent: Friday, May 20, 2016 4:11:52 AM
To: PHMSA PHP80 Response; PHMSA PHP500 Response
Subject: NRC#1148267: Pipeline - Tracy, CA (55 miles E of San Francisco, CA), unknown amount of crude oil spill

This report is forwarded for your situational awareness. CMC 6-1863

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***

Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1148267

INCIDENT DESCRIPTION
**** THIS IS A POTENTIAL RELEASE ****
*Report taken by: CIV ANTONAY GREER at 05:44 on 20-MAY-16
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area: UNKNOWN
Incident occurred on 20-MAY-16 at 02:05 local incident time.
Affected Medium: UNKNOWN *** POTENTIAL POLLUTION***

REPORTING PARTY
Name: ROBERT MARSHALL
Organization: SHELL PIPELINE
Address: 1801 PETROL RD
BAKERSFIELD, CA 93308

PRIMARY Phone: (661)9795275
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY
Name: N/A
Organization: SHELL PIPELINE
Address: 1801 PETROL RD
BAKERSFIELD, CA 93308
PRIMARY Phone: (661)9795275

INCIDENT LOCATION
County: ALAMEDA
City: TRACY State: CA
BETWEEN ALAMEDA AND SAN JUAQIN COUNTIES
*NO POSITION OR LEGALS PROVIDED

POTENTIALLY RELEASED MATERIAL(S)
CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT Qty in Water: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT
THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE.

SENSITIVE INFORMATION

INCIDENT DETAILS
Pipeline Type: FLOW
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN
---WATER INFORMATION---
Body of Water: UNKNOWN
Tributary of:
Nearest River Mile Marker:
Water Supply Contaminated: UNKNOWN

IMPACT
Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air: N			
Road: N	Major Artery:N		
Waterway: N			
Track: N			

Environmental Impact: UNKNOWN
Media Interest: UNKNOWN Community Impact due to Material:

REMEDIAL ACTIONS
* CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED
* LINE IS DOWN, VALVES ARE CLOSED.
Release Secured: UNKNOWN
Release Rate:
Estimated Release Duration:

WEATHER
Weather: UNKNOWN, °F

ADDITIONAL AGENCIES NOTIFIED

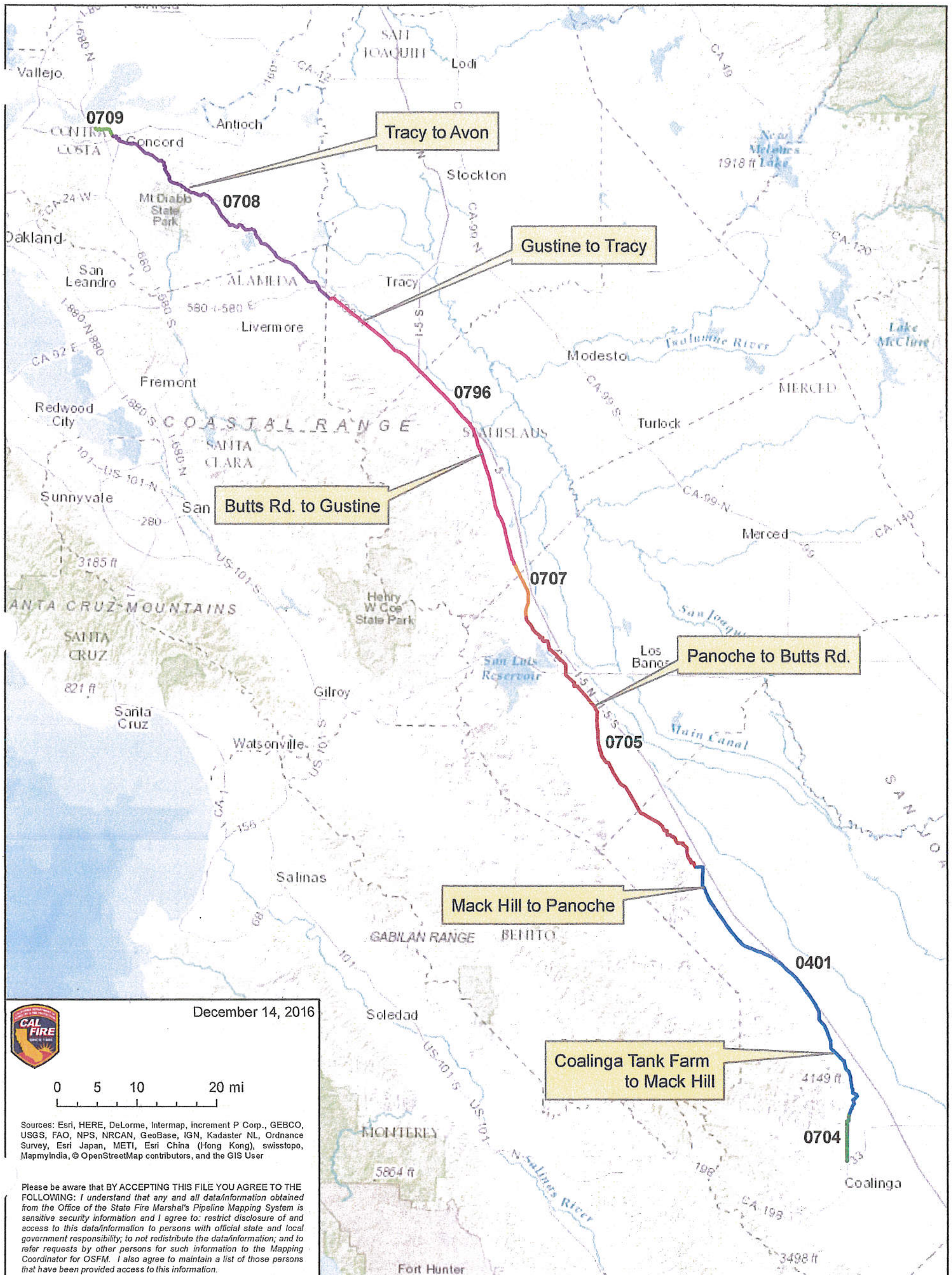
Federal:
State/Local: CA-OES
State/Local On Scene:
State Agency Number: 16-2999

NOTIFICATIONS BY NRC

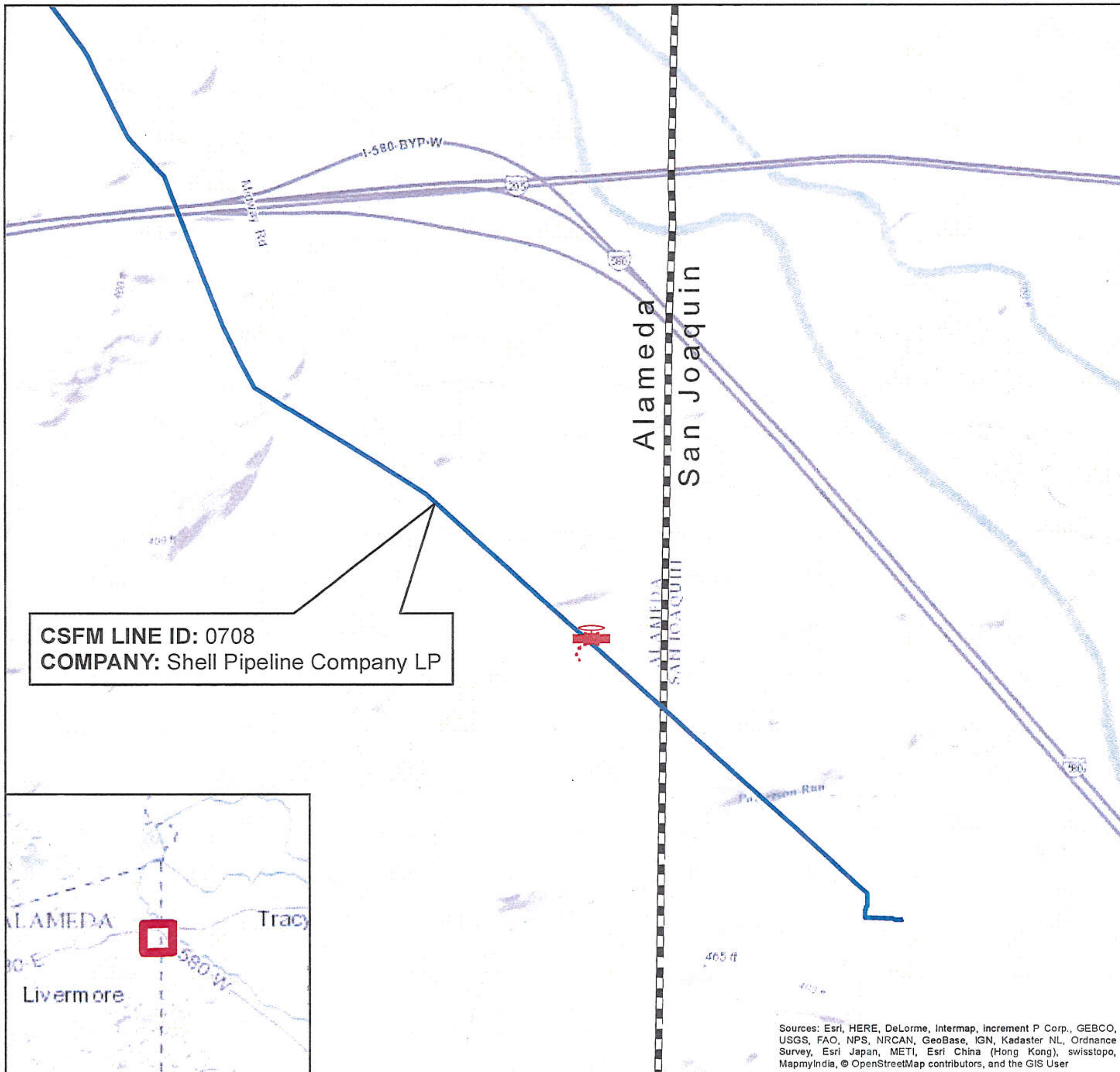
CA U.S. ATTORNEY'S OFFICE NORTH (MAIN OFFICE)
20-MAY-16 05:56 (415)4367077
CA DEPT OF FISH AND GAME (OFFICE OF SPILL PREVENTION AND RESPONSE)
20-MAY-16 05:56 (916)
CENTERS FOR DISEASE CONTROL (GRASP)
20-MAY-16 05:56 (770)4887100
CONTRA COSTA OFC OF SHERIFF (HOMELAND SECURITY UNIT)
20-MAY-16 05:56 (925)3139612
DHS PROTECTIVE SECURITY ADVISOR (PSA DESK)
20-MAY-16 05:56 (703)2355724
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
20-MAY-16 05:56 (202)3661863
U.S. EPA IX (MAIN OFFICE)
(415)2279500
FEMA REGION 09 (SITUATION AWARENESS UNIT)
20-MAY-16 05:56 (510)6277802
NORTHERN CA REG INTELLIGENCE CENTER (COMMAND CENTER SAN FRANCISCO)
20-MAY-16 05:56 (415)5752788
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
20-MAY-16 05:56 (202)2829201
NOAA RPTS FOR CA (MAIN OFFICE)
20-MAY-16 05:56 (206)5264911
NATIONAL RESPONSE CENTER HQ (AUTOMATIC REPORTS)
20-MAY-16 05:56 (202)2671136
NTSB PIPELINE (MAIN OFFICE)
20-MAY-16 05:56 (202)3146293
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
20-MAY-16 05:56 (202)3660568
SECTOR SAN FRANCISCO (MAIN OFFICE)
(415)3993547
CA STATE EMERGENCY SERVICES (MAIN OFFICE)
20-MAY-16 05:56 (916)2621621
STATE TERRORISM & THREAT ASSESS CTR (COMMAND CENTER SACRAMENTO)
20-MAY-16 05:56 (916)8741100

ADDITIONAL INFORMATION

*** END INCIDENT REPORT #1148267 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil


Tracy to Avon
Gustine to Tracy
Butts Rd. to Gustine
Panoche to Butts Rd.
Mack Hill to Panoche
Coalinga Tank Farm
to Mack Hill
0709
0708
0796
0707
0705
0401
0704
Vallejo
Antioch
Concord
Lodi
Stockton
Oakland
San Leandro
Livermore
Tracy
Modesto
Fremont
Redwood City
COASTAL RANGE
Turlock
Sunnyvale
Merced
SANTA CRUZ MOUNTAINS
Henry W Coe State Park
San Luis Reservoir
Los Banos
Gilroy
Santa Cruz
Watsonville
Salinas
GABILAN RANGE
Soledad
Coalinga
Fort Hunter Liggett
December 14, 2016
0 5 10 20 mi
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User
Please be aware that BY ACCEPTING THIS FILE YOU AGREE TO THE FOLLOWING: I understand that any and all data/information obtained from the Office of the State Fire Marshal's Pipeline Mapping System is sensitive security information and I agree to: restrict disclosure of and access to this data/information to persons with official state and local government responsibility; to not redistribute the data/information; and to refer requests by other persons for such information to the Mapping Coordinator for OSFM. I also agree to maintain a list of those persons that have been provided access to this information.

Shell Oil Spill Incident May 20, 2016



May 31, 2016

Spill Location

CSFM Pipeline 0708

County Line

0 0.15 0.3 0.6 mi

Please be aware that BY ACCEPTING THIS FILE YOU AGREE TO THE FOLLOWING: *I understand that any and all data/information obtained from the Office of the State Fire Marshal's Pipeline Mapping System is sensitive security information and I agree to: restrict disclosure of and access to this data/information to persons with official state and local government responsibility; to not redistribute the data/information; and to refer requests by other persons for such information to the Mapping Coordinator for OSFM. I also agree to maintain a list of those persons that have been provided access to this information.*

Pipeline Failure Investigation Report

Pipeline System: SJV North Heavy Crude Oil System **Operator:** Shell Pipeline Company LP

Operator ID: 31174 **Unit Number:** 0560A **Activity Number:** 20160520TMW1

Location: Tracy, California ([redacted] **Date of Occurrence:** May 20, 2016

Material Released: Crude oil **Quantity:** 500 barrels

PHMSA Arrival Time & Date: 1 PM/ May 20, 2016 **Total Damages $:** $4,540,000

Investigation Responsibility: X State _ **PHMSA** _ **NTSB** _Other _______

	Company Reported Apparent Cause:	***Company Reported Sub-Cause (from PHMSA Form 7000-1/7100.2):***
	Corrosion	
	Natural Force Damage	
	Excavation Damage	
	Other Outside Force Damage	
X	Material Failure (Pipe, Joint, Weld)	Pipe – Fatigue crack
	Equipment Failure	
	Incorrect Operation	
	Other	

	Accident/Incident Resulted in (check all that apply):	***Comments:***
X	Rupture	
	Leak	
	Fire	
	Explosion	
	Evacuation	Number of Persons: ______ Area: ______

Narrative Summary

Short summary of the Incident/Accident scenario

At 0035 hours (PST) May 20, 2016, Shell Pipeline Company's Control Center in Houston, TX detected a drop in operating pressure on the North San Joaquin Valley 24" Tracy to Avon crude oil pipeline (CSFM #0708). The Tracy pumps station immediately shut down on low suction pressure and the control center immediately shut down the entire pipeline system and immediately isolated the leaking section of pipe by closing the main line block valves. The failure occurred in an open field approximately ¾ of a mile downstream of the Tracy pump station. No waterways were impacted, no fire, injuries or death occurred. A 79.8' section of pipe containing the seam failure was cut out and replaced. Metallurgical examination of the failed pipe was conducted by Det Norske Veritas of Dublin, Ohio. After repairs were made, the entire line was hydrostatically tested and the line resumed operation on July 19, 2016

Region/State: **Western - California**

Principal Investigator: **Thomas M. Williams IV**

Date: 3/29/2017

Reviewed by: Chuck McDonald

Title: Supv PL Safety Engineer

Date: 3/29/2017

Pipeline Failure Investigation Report

Failure Location & Response	
Location (City, Township, Range, County/Parish): ***Outside of Tracy, Alameda County, California***	(Acquire Map)
Address or M.P. on Pipeline: [1] ***MP 136.7***	Type of Area (Rural, City): [1] ***Rural***
Coordinates of failure location (Latitude): [redacted]	(Longitude): [redacted]
Date: ***May 20, 2016***	Time of Failure: ***0035 PST***
Time Detected: ***0035 PST***	Time Located: ***0217 PST***
How Located: ***Ground Patrol***	

NRC Report #: ***1148267***	Time Reported to NRC: ***0244 PST 5/20/16***	Reported by: ***Bob Marshall, Shell Pipeline Company***

Type of Pipeline:

Gas Distribution	**Gas Transmission**	**Hazardous Liquid**	___ **LNG**
__ LP	__ Interstate Gas	__ Interstate Liquid	
__ Municipal	__ Intrastate Gas	*X* Intrastate Liquid	
__ Public Utility	__ Gas Gathering	__ Offshore Liquid	
__ Master Meter	__ Offshore Gas	__ Liquid Gathering	
	__ Offshore Gas - High H_2S	__ CO_2	
		__ Low Stress Liquid	
		__ HVL	

Pipeline Configuration (Regulator Station, Pump Station, Pipeline, etc.):
24" Pipeline from Tracy Station to Windmill Farms CSFM ID 0708

Operator/Owner Information	
Owner: ***San Pablo Bay*** Address: ***910 Louisiana Street*** ***Houston, Texas 77002***	Operator: ***Shell Pipeline Company LP*** Address: ***910 Louisiana Street*** ***Houston, Texas 77002***
Company Official: ***Greg Smith, President*** Phone No.: [redacted] Fax No.: **N/A**	Company Official: ***Greg Smith, President*** Phone No. [redacted] Fax No. **N/A**

Drug and Alcohol Testing Program Contacts *X* N/A

Drug Program Contact & Phone: Michael Courville, Operations Support Specialist, 713-241-0740

Alcohol Program Contact & Phone: Michael Courville, Operations Support Specialist, 713-241-0740

1 Photo documentation

Pipeline Failure Investigation Report

Damages	
Product/Gas Loss or Spill [(2)] ***500 barrels*** ***Amount Recovered 400 barrels***	Estimated Property Damage : ***$25,000*** Associated Damages [(3)] ***$2,930,000***

Description of Property Damage: ***$25,000 in property damage; $1,330,000 in operators' property damage and repairs; $1,585,000 in operators' emergency response; $1,600,000 in environmental remediation.***

Customers out of Service: __ Yes ***X*** No Number: ***N/A***
Suppliers out of Service: __ Yes ***X*** No Number: ***N/A***

Fatalities and Injuries ***X N/A***

Fatalities:	__ Yes	__ No	Company:	Contractor:	Public:
Injuries - Hospitalization:	__ Yes	__ No	Company:	Contractor:	Public:
Injuries - Non-Hospitalization:	__ Yes	__ No	Company:	Contractor:	Public:
Total Injuries (including Non-Hospitalization):			Company:	Contractor:	Public:

Name	Job Function	Yrs. w/ Comp.	Yrs. Exp.	Type of Injury

Drug/Alcohol Testing ***X N/A***

Were all employees that could have contributed to the incident, post-accident tested within the 2-hour time frame for alcohol or the 32-hour time frame for all other drugs?

__Yes __No

Job Function	Test Date & Time	Location	Results		Type of Drug
			Pos	Neg	

System Description

Describe the Operator's System: San Pablo Bay – North 20, Coalinga to Avon 20/24-inch pipeline system. Transports Crude oil from the San Joaquin Valley Gathering to refineries in the Martinez Bay Area.

Pipe Failure Description __ ***N/A***

Length of Failure (inches, feet, miles): (1)
Rupture, Fish Mouth, 4.5 inches by 45.2 inches

Position (Top, Bottom, include position on pipe, 6 O'clock): (1)	Description of Failure (Corrosion Gouge, Seam Split): (1)

2 Initial volume lost or spilled
3 Including cleanup cost

Pipeline Failure Investigation Report

Pipe Failure Description	___ N/A
3 O'clock	*Long seam*
Laboratory Analysis: *X* Yes ___ No (not yet completed) Performed by: *Det Norske Veritas (U.S.A.), Inc.*	
Preservation of Failed Section or Component: *X* Yes ___ No If Yes - Method: *Wrapped in plastic and crated for shipment to Det Norske Veritas (U.S.A.), Inc., Dublin, Ohio*	
In Custody of: *Det Norske Veritas (U.S.A.), Inc.*	
Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, direction of flow, etc. Bar Hole Test Survey Plot, if included, should be outlined with concentrations at test points. *N/A*	

Component Failure Description	*X* N/A
Component Failed: [1]	
Manufacturer:	Model:
Pressure Rating:	Size:
Other (Breakout Tank, Underground Storage):	

Pipe Data	___ N/A
Material: *Carbon Steel*	Wall Thickness/SDR: *0.260"*
Diameter (O.D.): *24"*	Installation Date: *1989*
SMYS: *X60*	Manufacturer: *Armco*
Longitudinal Seam: *DSAW*	Type of Coating: *3-layer Polyolefin*
Pipe Specifications (API 5L, ASTM A53, etc.) : *API 5L*	

Joining	*X* N/A
Type:	Procedure:
NDT Method:	Inspected: ___ Yes ___ No

Pressure @ Time of Failure @ Failure Site				___ N/A
Pressure @ Failure Site: *694 psi*	Elevation @ Failure Site:			
Pressure Readings @ Various Locations:			Direction from Failure Site	
Location/M.P./Station #	Pressure (psig)	Elevation (ft msl)	Upstream	Downstream
Tracy Kick off discharge	*694 psig*	*588 ft.*	*X*	
Marsh Creek suction	*365 psig*	*422 ft.*		*X*

Upstream Pump Station Data	___ N/A
Type of Product: *Crude Oil*	API Gravity: *15.2*
Specific Gravity: *N/A*	Flow Rate: *6,126 B.Ph.*
Pressure @ Time of Failure [4] *694 psi*	Distance to Failure Site: *1 mile*
High Pressure Set Point: *957 psi*	Low Pressure Set Point: *25 psi*

4 Obtain event logs and pressure recording charts

Pipeline Failure Investigation Report

Upstream Compressor Station Data	X N/A
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure [4]	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Operating Pressure	___ N/A
Max. Allowable Operating Pressure: ***936 psi***	Determination of MAOP: ***Pipe design pressure and 80% of hydrotest***
Actual Operating Pressure: ***694 psi***	
Method of Over Pressure Protection: ***relief valve***	
Relief Valve Set Point: ***645 psi***	Capacity Adequate? *X Yes* ___ No

Integrity Test After Failure	___ N/A
Pressure test conducted in place? (Conducted on Failed Components or Associated Piping): *X* Yes ___ No	
If No, tested after removal? ___ Yes No	
Method: **8 -hour Hydrotest and a 10 - minute Spike Hydrotest**	
Describe any failures during the test. **None**	

Soil/water Conditions @ Failure Site	___ N/A
Condition of and Type of Soil around Failure Site (Color, Wet, Dry, Frost Depth): Soil conditions – ***Dry, Pasture with Vegetation.***	
Type of Backfill (Size and Description): ***local backfill from landowner property***	
Type of Water (Salt, Brackish): ***No Water in area***	Water Analysis [5] ___ Yes *X* No

External Pipe or Component Examination	X N/A
External Corrosion? ___ Yes ___ No [1]	Coating Condition (Disbonded, Non-existent): [1]
Description of Corrosion:	
Description of Failure Surface (Gouges, Arc Burns, Wrinkle Bends, Cracks, Stress Cracks, Chevrons, Fracture Mode, Point of Origin):	
Above Ground: ___ Yes ___ No [1]	Buried: ___ Yes ___ No [1]
Stress Inducing Factors: [1]	Depth of Cover: [1]

Cathodic Protection	X N/A
P/S (Surface):	P/S (Interface):
Soil Resistivity: pH:	Date of Installation:
Method of Protection:	
Did the Operator have knowledge of Corrosion before the Incident? ___ Yes ___ No	
How Discovered? (Close Interval Survey, Instrumented Pig, Annual Survey, Rectifier Readings, ECDA, etc):	

Internal Pipe or Component Examination	X N/A
Internal Corrosion: ___ Yes ___ No [1]	Injected Inhibitors: ___ Yes ___ No
Type of Inhibitors:	Testing: ___ Yes ___ No

5 Attach copy of water analysis report

Pipeline Failure Investigation Report

Internal Pipe or Component Examination	***X N/A***
Results (Coupon Test, Corrosion Resistance Probe):	
Description of Failure Surface (MIC, Pitting, Wall Thinning, Chevrons, Fracture Mode, Point of Origin):	
Cleaning Pig Program: ___ Yes ___ No	Gas and/or Liquid Analysis: ___ Yes ___ No
Results of Gas and/or Liquid Analysis [6]	
Internal Inspection Survey: ___ Yes ___ No	Results [7]
Did the Operator have knowledge of Corrosion before the Incident? ___ Yes ___ No	
How Discovered? (Instrumented Pig, Coupon Testing, ICDA, etc.):	

Outside Force Damage	***X N/A***
Responsible Party:	Telephone No.:
Address:	
Work Being Performed:	
Equipment Involved: (1)	Called One Call System? ___ Yes ___ No
One Call Name:	One Call Report # [8]
Notice Date:	Time:
Response Date:	Time:
Details of Response:	
Was Location Marked According to Procedures? ___ Yes ___ No	
Pipeline Marking Type: (1)	Location: (1)
State Law Damage Prevention Program Followed? ___ Yes ___ No ___ No State Law	
Notice Required: ___Yes ___No	Response Required: ___ Yes ___ No
Was Operator Member of State One Call? ___ Yes ___ No	Was Operator on Site? ___ Yes ___ No
Did a deficiency in the Public Awareness Program contribute to the accident? ___Yes ___ No	
Is OSHA Notification Required? ___ Yes ___ No	

Natural Forces	***X N/A***
Description (Earthquake, Tornado, Flooding, Erosion):	

Failure Isolation	***__ N/A***
Squeeze Off/Stopple Location and Method: *N/A*	(1)
Valve Closed - ***Upstream***	I.D.: ***Tracy Station***

6 Attach copy of gas and/or liquid analysis report
7 Attach copy of internal inspection survey report
8 Attach copy of one-call report

Pipeline Failure Investigation Report

Failure Isolation	__ ***N/A***
Time: ***0038hrs. Pacific Time***	M.P.: ***136***
Valve Closed - Downstream: Time: ***0238hrs. Pacific Time***	I.D.: ***Marsh Creek*** M.P.: ***156***
Pipeline Shutdown Method: __ Manual __ Automatic __ SCADA ***X*** Controller __ ESD	
Failed Section Bypassed or Isolated: ***Isolated***	
Performed By: ***Derek Ferraro***	Valve Spacing: ***20 miles***

Odorization		***X N/A***
Gas Odorized: __ Yes __ No	Concentration of Odorant (Post Incident at Failure Site):	
Method of Determination: __ Yes __ No	% LEL: __ Yes __ No	% Gas In Air: __ Yes __ No
	Time Taken: __ Yes __ No	
Was Odorizer Working Prior to the Incident? __ Yes __ No	Type of Odorizer (Wick, By-Pass):	
Odorant Manufacturer: Model:	Type of Odorant:	
Amount Injected:	Monitoring Interval (Weekly):	
Odorization History (Leaks Complaints, Low Odorant Levels, Monitoring Locations, Distances from Failure Site):		

Weather Conditions	__ ***N/A***
Temperature: **55 °F**	Wind (Direction & Speed): **18 mph**
Climate (Snow, Rain): Weather: **Clear**, Visibility: **10 Miles.**	Humidity: **62%** Barometer: **29.71"Hg,**
Was Incident preceded by a rapid weather change? __ Yes X No	
Weather Conditions Prior to Incident (Cloud Cover, Ceiling Heights, Snow, Rain, Fog): **Temp - 80 °F/57 °F, Weather - Clear, Wind - 13 mph, Barometer 29.71"Hg, Visibility 10 Miles.**	

Gas Migration Survey	***X N/A***
Bar Hole Test of Area: __ Yes __ No	Equipment Used:
Method of Survey (Foundations, Curbs, Manholes, Driveways, Mains, Services) [9]	(1)

Environment Sensitivity Impact	__ ***N/A***
Location (Nearest Rivers, Body of Water, Marshlands, Wildlife Refuge, City Water Supplies that could be or were affected by the medium loss): ***No impacted water or wildlife*** (1)	
OPA Contingency Plan Available? ***X*** Yes __ No	Followed? ***X*** Yes __ No

Class Location/High Consequence Area	***X*** N/A
Class Location: 1 __ 2 __ 3 __ 4 __ ***N/A*** Determination: ***N/A***	HCA Area? ***X*** Yes __ No __ N/A Determination: Drinking Water & Ecological

9 Plot on site description page

Class Location/High Consequence Area	X N/A
Odorization Required? __ Yes __ No X N/A	

Pressure Test History (Expand List as Necessary)						__ N/A
	Req'd [10] Assessment Deadline Date	Test Date	Test Medium	Pressure (psig)	Duration (hrs)	% SMYS
Installation	*N/A*	*11/20/1989*	*Water*	*1200*	*8*	*92.3%*
Next						
Next						
Most Recent						
Describe any problems experienced during the pressure tests. *None*						

Internal Line Inspection/Other Assessment History (Expand List as Necessary)					__ N/A
	Req'd [10] Assessment Deadline Date	Assessment Date	Type of ILI Tool [11]	Other Assessment Method [12]	Indicated Anomaly If yes, describe below
Initial		*8/3/2005*	*MFL/GEOM*	*ILI*	__ Yes X No
Next	*8/3/2007*	*6/1/2007*	*MFL/GEOM*	*ILI*	X Yes __ No
Next	*6/1/2009*	*5/7/2009*	*MFL*	*ILI*	X Yes __ No
Next	*5/7/2011*	*4/20/2011*	*MFL/GEOM*	*ILI*	__ Yes *X No*
Next	*4/20/2013*	*6/27/2013*	*MFL*	*ILI*	__ Yes X No
Next	*6/27/2015*	*8/6/2015*	*MFL/GEOM*	*ILI*	__ Yes X No
Next		*12/3/2015*	*MFL-C*	*ILI*	X Yes __ No
Most Recent		*12/4/2015*	*UT-C*	*ILI*	X Yes __ No
N/A	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions. ***6/1/2007 – 3 preventative digs performed. 5/7/2009 – 2 preventive digs performed, 12/2015 - 2 digs performed.***					

Pre-Failure Conditions and Actions	__ N/A
Was there a known pre-failure condition requiring [10] the operator to schedule evaluation and remediation? __ Yes (describe below or on attachment) X No	
If there was such a known pre-failure condition, had the operator established and adhered to a required [10] evaluation and remediation schedule? Describe below or on attachment. __ Yes __ No X N/A	
Prior to the failure, had the operator performed the required [10] actions to address the threats that are now known to be related to the cause of this failure? ***X Yes*** __ No __ N/A List below or on an attachment such operator-identified threats, and operator actions taken prior to the accident.	
Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions.	

10 As required of Pipeline Integrity Management regulations in 49CFR Parts 192 and 195
11 MFL, TFI, UT, Combination, Geometry, etc.
12 ECDA, ICDA, SCCDA, "other technology," etc.

Pipeline Failure Investigation Report

Maps & Records	___ *N/A*
Are Maps and Records Current? [13] *X* Yes ___ No	
Comments:	

Leak Survey History	*X N/A*
Leak Survey History (Trend Analysis, Leak Plots):	

Pipeline Operation History	___ *N/A*
Description (Repair or Leak Reports, Exposed Pipe Reports):	
Did a Safety Related Condition Exist Prior to Failure? *X Yes* ___ No	Reported? *X Yes* ___ No
Unaccounted For Gas: **N/A**	
Over & Short/Line Balance (24 hr., Weekly, Monthly/Trend): **N/A**	

Operator/Contractor Error	*X N/A*
Name:	Job Function:
Title:	Years of Experience:
Training (Type of Training, Background):	
Was the person "Operator Qualified" as applicable to a precursor abnormal operating condition? ___Yes ___No ___N/A	
Was qualified individual suspended from performing covered task ___ Yes ___ No ___ N/A	
Type of Error (Inadvertent Operation of a Valve):	
Procedures that are required:	
Actions that were taken:	
Pre-Job Meeting (Construction, Maintenance, Blow Down, Purging, Isolation):	
Prevention of Accidental Ignition (Tag & Lock Out, Hot Weld Permit):	
Procedures conducted for Accidental Ignition:	
Was a Company Inspector on the Job? ___ Yes ___ No	
Was an Inspection conducted on this portion of the job? ___ Yes ___ No	
Additional Actions (Contributing factors may include number of hours at work prior to failure or time of day work being conducted):	
Training Procedures:	
Operation Procedures:	
Controller Activities:	

Name	Title	Years Experience	Hours on Duty Prior to Failure	Shift

13 Obtain copies of maps and records

Pipeline Failure Investigation Report

Operator/Contractor Error				X N/A

Alarm Parameters:
High/Low Pressure Shutdown:
Flow Rate:
Procedures for Clearing Alarms:
Type of Alarm:
Company Response Procedures for Abnormal Operations:
Over/Short Line Balance Procedures:
Frequency of Over/Short Line Balance:
Additional Actions:

Additional Actions Taken by the Operator ___N/A

Make notes regarding the emergency and Failure Investigation Procedures (Pressure reduction, Reinforced Squeeze Off, Clean Up, Use of Evacuators, Line Purging, closing Additional Valves, Double Block and Bleed, Continue Operating Downstream Pumps):

Line was shut down. Under reduced operating pressure the line was started up to push the heavy crude oil out of the line with a lighter crude oil to facilitate an extended shutdown. Crack tool logs were reevaluated by the vendor and additional repair and investigation digs were conducted on the three segments of the bigger pipeline system that contain the same type of pipe. Pressure tests with a spike test were conducted on all three segments of the line.

Photo Documentation (1)

Overall Area from best possible view. Pictures from the four points of the compass. Failed Component, Operator Action, Damages in Area,
Address Markings, etc.

Photo No.	Description	Photo No.	Description
1		16	
2		17	
3		18	
4		19	
5		20	
6		21	
7		22	
8		23	
9		24	
10		25	
11		26	
12		27	
13		28	
14		29	
15		30	

Pipeline Failure Investigation Report

Camera Type:

Additional Information Sources			
Agency	Name	Title	Phone Number
Police:			
Fire Dept.:			
State Fire Marshal:			
State Agency:			
NTSB:			
EPA:			
USCG:			
FBI:			
ATF:			
OSHA:			
Insurance Co.:			
FRA:			
MMS:			
Television:			
Newspaper:			
Other:			

Persons Interviewed		
Name	Title	Phone Number
Robert C. Marshall	**Emergency Response/Public Awareness**	[redacted]
Michael Bringham	**Facilities Manager, SJV Crude**	
Gary McNatt	**SJV Operations Supervisor**	
Dave Harder	**SJV Maintenance Supervisor**	
Alan Elliott	**Western Region Asset Integrity**	
Bryce Brown	**Rosen – Global Strategy Management**	

Event Log	
Sequence of events prior, during, and after the incident by time. (Consider the events of all parties involved in the incident, Fire Department and Police reports, Operator Logs and other government agencies.)	
Time / Date	Event

Pipeline Failure Investigation Report

Investigation Contact Log			
Time	Date	Name	Description

Failure Investigation Documentation Log				
Operator:	Unit #:	CPF #:	Date:	
Appendix Number	Documentation Description	Date Received	FOIA	
			Yes	No

Pipeline Failure Investigation Report

Site Description
Provide a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Photos should be taken from all angles with each photo documented. Additional areas may be needed in any area of this guideline.

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0047 EXPIRATION DATE: 12/31/2016
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	06/15/2016
	No.	20160184 - 21575 (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	Yes
Last Revision Date:	08/05/2016		
1. Operator's OPS-issued Operator Identification Number (OPID):	31174		
2. Name of Operator	SHELL PIPELINE CO., L.P.		
3. Address of Operator:			
3a. Street Address	910 LOUISIANA STREET 42ND FLOOR		
3b. City	HOUSTON		
3c. State	Texas		
3d. Zip Code	77002		
4. Local time *(24-hr clock)* and date of the Accident:	05/20/2016 00:35		
5. Location of Accident:			
Latitude:	[redacted]		
Longitude:			
6. National Response Center Report Number (if applicable):	1148267		
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	05/20/2016 02:44		
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil		
- Specify Commodity Subtype:			
- If "Other" Subtype, Describe:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend e.g. B2, B20, B100			
9. Estimated volume of commodity released unintentionally (Barrels):	500.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):			
11. Estimated volume of commodity recovered (Barrels):	400.00		
12. Were there fatalities?	No		
- If Yes, specify the number in each category:			
12a. Operator employees			
12b. Contractor employees working for the Operator			
12c. Non-Operator emergency responders			
12d. Workers working on the right-of-way, but NOT associated with this Operator			
12e. General public			
12f. Total fatalities (sum of above)			
13. Were there injuries requiring inpatient hospitalization?	No		
- If Yes, specify the number in each category:			
13a. Operator employees			
13b. Contractor employees working for the Operator			
13c. Non-Operator emergency responders			
13d. Workers working on the right-of-way, but NOT associated with this Operator			
13e. General public			

13f. Total injuries (sum of above)		
14. Was the pipeline/facility shut down due to the Accident?		Yes
- If No, Explain:		
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*		
14a. Local time and date of shutdown:		05/20/2016 00:37
14b. Local time pipeline/facility restarted:		05/23/2016 13:00
- Still shut down? (* Supplemental Report Required)		
15. Did the commodity ignite?		No
16. Did the commodity explode?		No
17. Number of general public evacuated:		0
18. Time sequence *(use local time, 24-hour clock)*:		
18a. Local time Operator identified Accident - effective 7-2014 changed to "Local time Operator identified failure":		05/20/2016 00:35
18b. Local time Operator resources arrived on site:		05/20/2016 02:17

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Accident onshore?		Yes
If Yes, Complete Questions (2-12)		
If No, Complete Questions (13-15)		
- If Onshore:		
2. State:		California
3. Zip Code:		95304
4. City		Tracy
5. County or Parish		Alameda
6. Operator-designated location:		Milepost/Valve Station
Specify:		137.3
7. Pipeline/Facility name:		North 20
8. Segment name/ID:		Tracy to Windmill Farms 24"
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?		No
10. Location of Accident:		Pipeline Right-of-way
11. Area of Accident (as found):		Underground
Specify:		Under soil
- If Other, Describe:		
Depth-of-Cover (in):		84
12. Did Accident occur in a crossing?		No
- If Yes, specify type below:		
- If Bridge crossing –		
Cased/ Uncased:		
- If Railroad crossing –		
Cased/ Uncased/ Bored/drilled		
- If Road crossing –		
Cased/ Uncased/ Bored/drilled		
- If Water crossing –		
Cased/ Uncased		
- Name of body of water, if commonly known:		
- Approx. water depth (ft) at the point of the Accident:		
- Select:		
- If Offshore:		
13. Approximate water depth (ft) at the point of the Accident:		
14. Origin of Accident:		
- In State waters - Specify:		
- State:		
- Area:		
- Block/Tract #:		
- Nearest County/Parish:		
- On the Outer Continental Shelf (OCS) - Specify:		
- Area:		
- Block #:		
15. Area of Accident:		

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:		Intrastate
2. Part of system involved in Accident:		Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:		
3. Item involved in Accident:		Pipe
- If Pipe, specify:		Pipe Body
3a. Nominal diameter of pipe (in):		24

3b. Wall thickness (in):	.260
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	60,000
3d. Pipe specification:	5LX
3e. Pipe Seam , specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	ARMCO
3g. Year of manufacture:	1982
3h. Pipeline coating type at point of Accident, specify:	Polyolefin
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	1989
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other, Describe:	
Approx. size: in. (widest opening) by	4.5
in. (length circumferentially or axially)	45.2
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	No
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	
- Vegetation	
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	Yes
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's	

Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
- Unusually Sensitive Area (USA) - Ecological	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
8. Estimated cost to Operator – effective 12-2012, changed to "Estimated Property Damage":	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 12-2012, "paid/reimbursed by the Operator" removed	$ 25,000
8b. Estimated cost of commodity lost	$ 0
8c. Estimated cost of Operator's property damage & repairs	$ 1,330,000
8d. Estimated cost of Operator's emergency response	$ 1,585,000
8e. Estimated cost of Operator's environmental remediation	$ 1,600,000
8f. Estimated other costs	$ 0
Describe:	
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 4,540,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	694.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	936.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f below*) effective 12-2012, changed to *"(Complete 5.a – 5.e below)"*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	16,125
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply*)	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, Which operational factors complicate execution? (*select all that apply*)	

- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
- If Yes:	
7a. Was it operating at the time of the Accident?	Yes
7b. Was it fully functional at the time of the Accident?	Yes
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
Provide an explanation for why not:	The Controllers response was compliant and effective. The size and consequence of the release was minimized as required by procedure. Notification to field personnel was compliant to notification to the Console Supervisor. There were no issues to note in regards to Control Center response. There were no fatigue related issues. No drug testing was required.
- Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION		
1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?		No
- If Yes:		
1a. Specify how many were tested:		
1b. Specify how many failed:		
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?		No
- If Yes:		
2a. Specify how many were tested:		
2b. Specify how many failed:		

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:		G5 - Material Failure of Pipe or Weld
G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column		
Corrosion Failure – Sub-Cause:		
- If External Corrosion:		
1. Results of visual examination:		
- If Other, Describe:		
2. Type of corrosion: *(select all that apply)*		
- Galvanic		
- Atmospheric		
- Stray Current		
- Microbiological		
- Selective Seam		
- Other:		
- If Other, Describe:		
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*		
- Field examination		
- Determined by metallurgical analysis		
- Other:		
- If Other, Describe:		
4. Was the failed item buried under the ground?		
- If Yes :		
4a. Was failed item considered to be under cathodic protection at the time of the Accident?		
If Yes - Year protection started:		
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?		
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?		
If "Yes, CP Annual Survey" – Most recent year conducted:		
If "Yes, Close Interval Survey" – Most recent year conducted:		
If "Yes, Other CP Survey" – Most recent year conducted:		
- If No:		
4d. Was the failed item externally coated or painted?		
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?		
- If Internal Corrosion:		
6. Results of visual examination:		
- Other:		
7. Type of corrosion *(select all that apply)*: -		
- Corrosive Commodity		
- Water drop-out/Acid		
- Microbiological		
- Erosion		
- Other:		
- If Other, Describe:		
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -		
- Field examination		

- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:		
G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column		
Natural Force Damage – Sub-Cause:		
- If Earth Movement, NOT due to Heavy Rains/Floods:		
1. Specify:		
- If Other, Describe:		
- If Heavy Rains/Floods:		
2. Specify:		
- If Other, Describe:		
- If Lightning:		
3. Specify:		
- If Temperature:		
4. Specify:		
- If Other, Describe:		
- If Other Natural Force Damage:		
5. Describe:		
Complete the following if any Natural Force Damage sub-cause is selected.		
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?		
6a. If Yes, specify: *(select all that apply)*		
- Hurricane		
- Tropical Storm		
- Tornado		
- Other		
- If Other, Describe:		
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column		
Excavation Damage – Sub-Cause:		
- If Previous Damage due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.		
1. Has one or more internal inspection tool collected data at the point of the Accident?		
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -		
- Magnetic Flux Leakage		
Most recent year conducted:		
- Ultrasonic		
Most recent year conducted:		
- Geometry		
Most recent year conducted:		
- Caliper		
Most recent year conducted:		
- Crack		
Most recent year conducted:		
- Hard Spot		
Most recent year conducted:		
- Combination Tool		
Most recent year conducted:		
- Transverse Field/Triaxial		
Most recent year conducted:		
- Other		
Most recent year conducted:		
Describe:		
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?		
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?		
- If Yes:		
Most recent year tested:		
Test pressure (psig):		
4. Has one or more Direct Assessment been conducted on the pipeline segment?		
- If Yes, and an investigative dig was conducted at the point of the Accident:		
Most recent year conducted:		
- If Yes, but the point of the Accident was not identified as a dig site:		
Most recent year conducted:		
5. Has one or more non-destructive examination been conducted at the		

point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

Complete the following if Excavation Damage by Third Party is selected as the sub-cause.

6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	

Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.

7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well)*:	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	

G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*

Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	

- Tornado		
- Heavy Rains/Flood		
- Other		
- If Other, Describe:		
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.		
3. Has one or more internal inspection tool collected data at the point of the Accident?		
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:		
- Magnetic Flux Leakage		
Most recent year conducted:		
- Ultrasonic		
Most recent year conducted:		
- Geometry		
Most recent year conducted:		
- Caliper		
Most recent year conducted:		
- Crack		
Most recent year conducted:		
- Hard Spot		
Most recent year conducted:		
- Combination Tool		
Most recent year conducted:		
- Transverse Field/Triaxial		
Most recent year conducted:		
- Other		
Most recent year conducted:		
Describe:		
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?		
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?		
- If Yes:		
Most recent year tested:		
Test pressure (psig):		
6. Has one or more Direct Assessment been conducted on the pipeline segment?		
- If Yes, and an investigative dig was conducted at the point of the Accident:		
Most recent year conducted:		
- If Yes, but the point of the Accident was not identified as a dig site:		
Most recent year conducted:		
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?		
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:		
- Radiography		
Most recent year conducted:		
- Guided Wave Ultrasonic		
Most recent year conducted:		
- Handheld Ultrasonic Tool		
Most recent year conducted:		
- Wet Magnetic Particle Test		
Most recent year conducted:		
- Dry Magnetic Particle Test		
Most recent year conducted:		
- Other		
Most recent year conducted:		
Describe:		
- If Intentional Damage:		
8. Specify:		
- If Other, Describe:		
- If Other Outside Force Damage:		
9. Describe:		
G5 - Material Failure of Pipe or Weld - only one sub-cause can be selected from the shaded left-hand column		
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."		
Material Failure of Pipe or Weld – Sub-Cause:		Original Manufacturing-related (NOT girth weld or other welds formed in the field)

1. The sub-cause shown above is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	Yes
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	Yes
Specify:	Mechanically-Induced Fatigue prior to installation (such as during transport of pipe)
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: *(select all that apply)*:	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	Yes
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	Yes
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	Yes
Most recent year run:	2015
- Ultrasonic	Yes
Most recent year run:	2015
- Geometry	Yes
Most recent year run:	2013
- Caliper	
Most recent year run:	
- Crack	Yes
Most recent year run:	2015
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	Yes
Most recent year run:	2015
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	Yes
- If Yes:	
Most recent year tested:	1989
Test pressure (psig):	1,190.00
7. Has one or more Direct Assessment been conducted on the pipeline segment?	No
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	No

8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -		
- Radiography		
Most recent year conducted:		
- Guided Wave Ultrasonic		
Most recent year conducted:		
- Handheld Ultrasonic Tool		
Most recent year conducted:		
- Wet Magnetic Particle Test		
Most recent year conducted:		
- Dry Magnetic Particle Test		
Most recent year conducted:		
- Other		
Most recent year conducted:		
Describe:		
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column		
Equipment Failure – Sub-Cause:		
- If Malfunction of Control/Relief Equipment:		
1. Specify: *(select all that apply)* -		
- Control Valve		
- Instrumentation		
- SCADA		
- Communications		
- Block Valve		
- Check Valve		
- Relief Valve		
- Power Failure		
- Stopple/Control Fitting		
- ESD System Failure		
- Other		
- If Other – Describe:		
- If Pump or Pump-related Equipment:		
2. Specify:		
- If Other – Describe:		
- If Threaded Connection/Coupling Failure:		
3. Specify:		
- If Other – Describe:		
- If Non-threaded Connection Failure:		
4. Specify:		
- If Other – Describe:		
- If Other Equipment Failure:		
5. Describe:		
Complete the following if any Equipment Failure sub-cause is selected.		
6. Additional factors that contributed to the equipment failure: *(select all that apply)*		
- Excessive vibration		
- Overpressurization		
- No support or loss of support		
- Manufacturing defect		
- Loss of electricity		
- Improper installation		
- Mismatched items (different manufacturer for tubing and tubing fittings)		
- Dissimilar metals		
- Breakdown of soft goods due to compatibility issues with transported commodity		
- Valve vault or valve can contributed to the release		
- Alarm/status failure		
- Misalignment		
- Thermal stress		
- Other		
- If Other, Describe:		
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column		

Incorrect Operation – Sub-Cause:	
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	
- If Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

5/20/16 00:35hrs PT the 24" pipe segment from Tracy to Windmill Farms ruptured. The pipeline Houston Control Center SCADA detected an increase in flow rate and drop in discharge pressure. The Pump Station immediately shutdown on low suction. The Controller took action to shutdown the entire pipeline system and isolate the pipeline. Notifications were made to the field supervisor, the Control Center Supervisor. Personnel were sent to the area of the pump station to locate the exact location of the release. Following the replacement of the failed pipe joint the CSFM gave permission to displace the heavy crude oil from the pipeline with light crude oil before an agreed plan of action on the vintage pipe which failed. Inspections and repairs were initiated, along with hydro-static pressure testing of effected segments. The pipeline was re-started with the approval of the CSFM on July 19, 2016. The failed pipe was examined at a metallurgical laboratory. SPLC's Subject Matter Expert (SME) reviewed the analysis.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Richard Klasen
Preparer's Title	Regulatory Specialist
Preparer's Telephone Number	[redacted]
Preparer's E-mail Address	[redacted]
Preparer's Facsimile Number	[redacted]
Authorized Signer Name	Deborah Price
Authorized Signer Title	Pipeline Ops Regulatory Manager
Authorized Signer Telephone Number	[redacted]
Authorized Signer Email	[redacted]
Date	08/05/2016

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 12/31/2016

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	06/15/2016
	No.	20160184 - 21442 (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
	Yes		

Last Revision Date:	
1. Operator's OPS-issued Operator Identification Number (OPID):	31174
2. Name of Operator	SHELL PIPELINE CO., L.P.
3. Address of Operator:	
3a. Street Address	910 LOUISIANA STREET. 42ND FLOOR
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code	77002
4. Local time *(24-hr clock)* and date of the Accident:	05/20/2016 00:35
5. Location of Accident:	
Latitude:	[redacted]
Longitude:	
6. National Response Center Report Number (if applicable):	1148267
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	05/20/2016 02:44
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend e.g. B2, B20, B100	
9. Estimated volume of commodity released unintentionally (Barrels):	500.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	
11. Estimated volume of commodity recovered (Barrels):	400.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	

13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	05/20/2016 00:37
14b. Local time pipeline/facility restarted:	05/23/2016 13:00
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	0
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident - effective 7- 2014 changed to "Local time Operator identified failure":	05/20/2016 00:35
18b. Local time Operator resources arrived on site:	05/20/2016 02:17

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	California
3. Zip Code:	95304
4. City	Tracy
5. County or Parish	Alameda
6. Operator-designated location:	Milepost/Valve Station
Specify:	137.3
7. Pipeline/Facility name:	North 20
8. Segment name/ID:	Tracy to Windmill Farms 24"
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	84
12. Did Accident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Intrastate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Pipe
- If Pipe, specify:	Pipe Body
3a. Nominal diameter of pipe (in):	24

3b. Wall thickness (in):	.260
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	60,000
3d. Pipe specification:	5LX
3e. Pipe Seam , specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	ARMCO
3g. Year of manufacture:	1982
3h. Pipeline coating type at point of Accident, specify:	Polyolefin
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	1989
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other, Describe:	
Approx. size: in. (widest opening) by	4.5
in. (length circumferentially or axially)	56.4
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	No
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	
- Vegetation	
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	Yes
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's	

Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
- Unusually Sensitive Area (USA) - Ecological	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
8. Estimated cost to Operator -- effective 12-2012, changed to "Estimated Property Damage":	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 12-2012, "paid/reimbursed by the Operator" removed	$ 250,000
8b. Estimated cost of commodity lost	$ 0
8c. Estimated cost of Operator's property damage & repairs	$ 1,500,000
8d. Estimated cost of Operator's emergency response	$ 1,050,000
8e. Estimated cost of Operator's environmental remediation	$ 1,000,000
8f. Estimated other costs	$ 0
Describe:	
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 3,800,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	694.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	936.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - *(Complete 5a. – 5f below)* effective 12-2012, changed to *"(Complete 5.a – 5.e below)"*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	16,125
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? *(select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, Which operational factors complicate execution? *(select all that apply)*	

- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
- If Yes:	
7a. Was it operating at the time of the Accident?	Yes
7b. Was it fully functional at the time of the Accident?	Yes
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
Provide an explanation for why not:	The Controllers response was compliant and effective. The size and consequence of the release was minimized as required by procedure. Notification to field personnel was compliant to notification to the Console Supervisor. There were no issues to note in regards to Control Center response. There were no fatigue related issues. No drug testing was required.
- Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	
1b. Specify how many failed:	
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G5 - Material Failure of Pipe or Weld

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

Corrosion Failure – Sub-Cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
☐4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	

- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:	
G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Previous Damage due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the	

point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one sub-cause can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	

- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	Original Manufacturing-related (NOT girth weld or other welds formed in the field)

1. The sub-cause shown above is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	Yes
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related Or If Original Manufacturing-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	Yes
Specify:	Mechanically-induced Fatigue prior to Installation (such as during transport of pipe)
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: *(select all that apply)*:	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	Yes
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	Yes
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	Yes
Most recent year run:	2015
- Ultrasonic	Yes
Most recent year run:	2015
- Geometry	Yes
Most recent year run:	2013
- Caliper	
Most recent year run:	
- Crack	Yes
Most recent year run:	2015
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	Yes
Most recent year run:	2015
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	Yes
- If Yes:	
Most recent year tested:	1989
Test pressure (psig):	1,190.00
7. Has one or more Direct Assessment been conducted on the pipeline segment?	No
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	No

8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column

Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	

G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column

Incorrect Operation – Sub-Cause:	
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	
- If Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

5/20/16 00:35hrs PT the 24" pipe segment from Tracy to Windmill Farms ruptured. The pipeline Houston Control Center SCADA detected an increase in flow rate and drop in discharge pressure. The Pump Station immediately shutdown on low suction. The Controller took action to shutdown the entire pipeline system and isolate the pipeline. Notifications were made to the field supervisor, the Control Center Supervisor. Personnel were sent to the area of the pump station to locate the exact location of the release.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Richard Klasen
Preparer's Title	Regulatory Specialist
Preparer's Telephone Number	[redacted]
Preparer's E-mail Address	[redacted]
Preparer's Facsimile Number	[redacted]
Authorized Signer Name	Deborah Price
Authorized Signer Title	Pipeline Ops Regulatory Manager
Authorized Signer Telephone Number	[redacted]
Authorized Signer Email	[redacted]
Date	06/15/2016

DNV·GL

Final Report

Metallurgical Analysis of May 20, 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System

Shell Pipeline Company
Houston, Texas

Report No.: OAPUS311MPHB (PP158491)
November 7, 2016

Project Name:	Metallurgical Analysis of May 20 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System
Customer:	Shell Pipeline Company
Contact Person:	Taylor Shie
Date of Issue:	November 7, 2016
Project No.:	PP158491
Organization Unit:	Incident Investigation
Report No.:	OAPUS311MPHB (PP158491)

DET NORSKE VERITAS (U.S.A.), INC. (DNV GL)
Materials & Corrosion Technology Center
Incident Investigation
5777 Frantz Road
Dublin, OH 43017-1886
United States
Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnvgl.com

Task and Objective:

Please see Executive Summary.

Prepared by	Verified by	Approved by
Michiel P. Brongers, P.E. Principal Engineer	John A. Beavers, Ph.D., FNACE Senior Principal Engineer	David M. Norfleet, Ph.D., P.E. Head of Section – Incident Investigation

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Executive Summary

Shell Pipeline Company, LP (*SPLC*) retained Det Norske Veritas (U.S.A.), Inc. (*DNV GL*) to perform a metallurgical analysis of a rupture that occurred on the Tracy to Windmill portion of the San Pablo Bay Pipeline System. The failure occurred on May 20, 2015 in Tracy, California, approximately 4,068 feet from the nearest upstream (U/S) pump station; the Tracy Pump Station.

Tracy to Windmill is part of a 177.77 mile long segment of the San Pablo Bay Pipeline System consisting of 20-inch and 24-inch diameter pipe that originates at the Coalinga Station in Coalinga, CA and terminates at the Shell Martinez Refinery in Avon, CA. The Coalinga to Avon segment was originally installed in 1967.

In 1989, three portions, totaling 12.55 miles, of the pipeline were replaced with 24-inch diameter by 0.260 inch wall, API 5LX Grade X60 double submerged arc-welded (DSAW) line pipe manufactured by Armco Steel in Houston, TX. The Tracy to Windmill portion, which is where the failure occurred, consists of 3.05 miles of the 12.55 miles of Armco line pipe installed in 1989.

Historical information indicates that the Armco line pipe used to construct the 12.55 miles of pipeline was stored for approximately 7 years following manufacturing and then was shipped from the northeastern United States to Coalinga, California for construction. The 12.55 miles of the replaced pipeline were externally coated with a 3-layer coating, comprised of fusion-bonded epoxy (FBE) on the pipe surface, a mastic coating, and an external polyolefin wrap. The pipeline has an impressed current cathodic protection (CP) system.

The pipeline operates in heavy crude service, with temperatures up to 180°F. On the day of the failure, the maximum allowable operating pressure (MAOP) of the pipeline was 936 psig, which corresponds to 72.0% of the specified minimum yield strength (SMYS). The segment operated with aggressive pressure cycling in the period leading up to the failure. The pressure at the time and location of the failure was estimated to be 665 psig, which corresponds to 51.2% of SMYS.

The most recent hydrostatic pressure test prior to the failure was performed in 1990. A minimum pressure of 1181 psig (90% of SMYS) was held for four hours. The most recent in-line inspections (ILIs), using a circumferential magnetic flux leakage (CMFL) tool and an ultrasonic testing crack detection (UT/CD) tool, were performed on 12/03/2015 and 12/04/2015, respectively. No anomalies in the failed joint were reported in the CMFL final report issued on 03/07/2016 or in the UT/CD final report issued on 05/02/2016.

A pipe section that contained the rupture was delivered to DNV GL for metallurgical analysis. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

The results of the metallurgical analysis indicate that the pipe joint ruptured at a fatigue crack that initiated at the toe of the DSAW seam weld on the inside surface of the pipe. Likely contributing factors include the peaked geometry of the failed pipe joint at the seam weld that introduced a bending stress, corrosion micro-pits on the ID surface that provided initiation sites, aggressive pressure cycling of the pipeline, and possibly an environmental effect on crack growth.

The fatigue crack initiation and propagation most likely occurred while in service. However, transit fatigue during transportation of the pipe cannot be ruled out as a contributing factor. Shell reported to have records of rail transportation per API 5L1 for the first portion of the journey, from Houston Texas to the northeast of the U.S. For the second portion of the journey, from the northeast to Coalinga California, verbal information indicates that API 5L1 would have been specified per industry norms, but written records have not been located.

The following steps were performed for this analysis:

- Visual inspection and photography,
- Removal of remnant coating still adhered to the pipe,
- Dimensional measurements,
- Magnetic particle inspection (MPI),
- Removal, cleaning and visual inspection of samples,
- Light microscopy and scanning electron microscopy of fracture surfaces (SEM),
- Examination of metallographically prepared cross-sections,
- Energy dispersive spectroscopy (EDS),
- Mechanical testing (duplicate tensile tests and full Charpy V-notch curves),
- Chemical analysis of steel samples, and
- Failure pressure calculations using CorLAS™.

Summary of observations:

- The pipe joint that ruptured contained several types of mill anomalies at the long seam weld, including peaking, weld overlap, and weld undercut.
- The fatigue crack at the rupture origin was 6.96 inches long and initiated from small (50-100 micron) pits along the internal toe of the DSAW. There was no evidence of a pre-existing weld-type defect at this location. The long-seam weld was located at the 3:26 o'clock orientation.
- MPI testing revealed other crack-like flaws on the pipe joint that failed, at approximately 2.7 feet D/S and 7.7 feet D/S of the rupture origin along the internal surface of the DSAW. The largest feature (MPI Indication 1a) was 4.25 inches in length and 0.125 inches depth (48.1% of 0.260 inches nominal wall thickness) at the deepest location.
- Qualitative spot testing indicated the presence of sulfides on the fracture surface at the failure origin, which is not uncommon in crude oil pipelines.
- Cross-sections showed that cracks at weld toes at locations away from the rupture were filled with sulfur-containing products, which is not uncommon in crude oil pipelines.
- There was no evidence of external corrosion on the pipe section.
- No MPI indications were identified on portions of the longitudinal seam weld of the U/S or D/S joints that were examined; 1.58 feet of the U/S joint and 1.79 feet of the D/S joint.
- The tensile properties of the failed joint and the joints U/S and D/S of the failed joint meet the tensile requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The Charpy V-notch (CVN) properties of the base metal of the failed joint are typical for the vintage and grade of line pipe steel. The seam weld HAZ had better fracture toughness properties than the base metal, with a slightly higher upper shelf impact energy and lower 85% FATT temperature.
- The composition of the base metal of the failed joint and the joints U/S and D/S of the failed joint meets requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The microstructures of the pipe joints are typical for the vintage and grade of line pipe steel.
- The estimated failure pressure using mechanical properties of the heat affected zone and the flaw profile that ruptured is 664 psig, which is close to the calculated pressure at the failure location and time of failure (665 psig).

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List of Acronyms

BDWTT	Battelle Drop Weight Tear Test
CCW	Counter Clockwise (orientation)
CMFL	Circumferential Magnetic Flux Leakage (tool)
CP	Cathodic Protection
CVN	Charpy V-Notch (impact testing)
CW	Clockwise (orientation)
D/S	Downstream
DSAW	Double Submerged Arc-Welded (pipe)
EDS	Energy Dispersive Spectroscopy
ERW	Electric Resistance Welded (pipe)
FATT	Failure Appearance Transition Temperature
FBE	Fusion-Bonded Epoxy
GW	Girth Weld
HAZ	Heat Affected Zone
HV	Vickers Hardness
ID	Inside Diameter (surface)
ILI	In-Line Inspection
MAOP	Maximum Allowable Operating Pressure
MPI	Magnetic Particle Inspection
OD	Outside Diameter (surface)
SEM	Scanning Electron Microscope
SMYS	Specified Minimum Yield Strength
SSC	Sulfide Stress Cracking
U/S	Upstream
UT/CD	Ultrasonic Testing Crack Detection (tool)
UTS	Ultimate Tensile Strength
wt	Wall Thickness
YS	Yield Strength

1.0 BACKGROUND

Shell Pipeline Company, LP (*SPLC*) retained Det Norske Veritas (U.S.A.), Inc. (*DNV GL*) to perform a metallurgical analysis of a rupture that occurred on the Tracy to Windmill portion of the San Pablo Bay Pipeline System. The failure occurred on May 20, 2015 in Tracy, California, approximately 4,068 feet from the nearest upstream (U/S) pump station; the Tracy Pump Station.

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Historical information indicates that the Armco line pipe used to construct the 12.55 miles of pipeline was stored for approximately 7 years following manufacturing and then was shipped from the northeastern United States to Coalinga, California for construction. The 12.55 miles of the replaced pipeline were externally coated with a 3-layer coating, comprised of fusion-bonded epoxy (FBE) on the pipe surface, a mastic coating, and an external polyolefin wrap. The pipeline has an impressed current cathodic protection (CP) system.

The pipeline operates in heavy crude service, with temperatures up to 180°F. On the day of the failure, the maximum allowable operating pressure (MAOP) of the pipeline was 936 psig, which corresponds to 72.0% of the specified minimum yield strength (SMYS). The segment operated with aggressive pressure cycling in the period leading up to the failure. The pressure at the time and location of the failure was estimated to be 665 psig, which corresponds to 51.2% of SMYS.

The most recent hydrostatic pressure test prior to the failure was performed in 1990. A minimum pressure of 1181 psig (90% of SMYS) was held for four hours. The most recent in-line inspections (ILIs), using a circumferential magnetic flux leakage (CMFL) tool and an ultrasonic testing crack detection (UT/CD) tool, were performed on 12/03/2015 and 12/04/2015, respectively. No anomalies in the failed joint were reported in the CMFL final report issued on 03/07/2016 or in the UT/CD final report issued on 05/02/2016.

A pipe section that contained the rupture was delivered to DNV GL for metallurgical analysis:

- a 29.81 foot long pipe section that contains the 26.44 feet long failed joint, 1.58 feet of the upstream U/S joint, and 1.79 feet of the downstream (D/S) joint.

The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

2.0 TECHNICAL APPROACH

The procedures used in the analysis were in accordance with industry-accepted standards. Five of the general standards governing terminology, specific metallographic procedures, mechanical testing, and chemical analysis used are as follows:

- ASTM E7, "Standard Terminology Relating to Metallography."
- ASTM E3, "Standard Methods of Preparation of Metallographic Specimens."
- ASTM E8, "Test Methods for Tension Testing of Metallic Materials."
- ASTM E23, "Standard Test Methods for Notched Bar Impact Testing of Metallic Materials."
- ASTM A751, "Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products."

The following steps were performed for this analysis. The pipe section was visually inspected and photographed. Wall thicknesses and diameters were measured on the ends of the pipe section where coating was removed and there was no measurable corrosion. Remnant coating, which still adhered to the pipe, adjacent to the failure location, was removed. Magnetic particle inspection (MPI) was performed on the internal pipe surfaces at areas adjacent to the rupture location, as well as along the internal surface of the longitudinal seam welds associated with the pipe joints. No MPI was deemed necessary on the external pipe surfaces because the failure initiated from the inside. Prior to MPI, the regions examined were cleaned with a degreaser (PreSolve®).

The fracture surfaces were cleaned with a degreaser and optically examined, and photographed. The length and depths of a pre-existing flaw on the fracture surface were measured to produce a flaw profile. Fracture surface samples were removed from the suspected rupture origin on the clockwise (CW) fracture surface, cleaned with a degreaser and methanol, and examined at high magnifications in a scanning electron microscope (SEM) to document the fracture morphology. Transverse cross-sections were removed from two areas at the suspected rupture origin and from two linear indications identified approximately 2.7 feet and approximately 7.7 feet downstream of the rupture origin by MPI.

In addition, transverse cross-sections were removed from the longitudinal seam weld of the ruptured joint and U/S and D/S joints at areas away from the rupture or other MPI indications. The cross-sections were mounted, polished, and etched; see Figure 1 for locations. Light photomicrographs were taken to document the fracture morphology and steel microstructure. SEM with energy dispersive spectroscopy (EDS) was performed on metallographically prepared cross-sections of the MPI-indications, to analyze for the presence of sulfur and other elements. Micro-hardness testing (Vickers - 500 g load) was performed on the metallographic mounts to determine hardness.

Mechanical (duplicate tensile tests and full Charpy V-notch [CVN] curves) testing was performed on specimens removed from the base metal and seam weld of the pipe joint that ruptured to determine the tensile and fracture toughness properties. The Charpy specimens across the seam weld were notched in the heat-affected zone (HAZ) of the same weld toe associated with the rupture. Mechanical (duplicate tensile tests) testing was also performed on specimens removed from the base metal of the U/S and D/S joints to determine tensile properties. Chemical analyses were performed on steel samples removed from the pipe joint that ruptured and the U/S and D/S joints to determine the compositions.

CorLAS™ calculations were performed to estimate the failure pressure of the pipe joint that ruptured based on the pipe geometry, measured mechanical properties, and the measured flaw profile.[1] These values were compared with the calculated pressure at the failure location at the time of the failure.

3.0 RESULTS AND DISCUSSION

3.1 Optical Examination

Figure 2 shows a photograph of the pipe section in the as-received condition. The pipe section was wrapped with plastic and duct tape, with the failure location facing up during transit. Figure 3 is a photograph of the pipe section near the rupture after removal of the protective wrappings. The pipe section was 29.81 feet in length and contained reference markings identifying flow direction and clock orientation. It contained the 26.44 feet long failed joint, 1.58 feet of the U/S joint, and 1.79 feet of the D/S joint.

A stencil on the external surface of the polyolefin wrap "ERW, 24 OD X .260" WT 66LBS/FT", towards the U/S end of the failed joint, suggests that the pipe section is comprised of 24-inch diameter by 0.260-inch wall line pipe steel with a longitudinal electric resistance

1 CorLAS™ is a computer program developed by CC Technologies Systems, Inc., which is now Det Norske Veritas (U.S.A.), Inc., to evaluate crack-like flaws in pipelines based on inelastic fracture mechanics.

welded (ERW) seam. However, the morphology of the longitudinal seam weld on the failed pipe section is consistent with a DSAW seam, not an ERW seam.

Diameters and wall thicknesses were measured on the U/S and D/S ends of the pipe section (U/S and D/S joints). The diameter measurements were made after locally removing the three-layer coating. The diameter of the U/S joint was 24.2 inches between the 12 and 6 o'clock orientations, and 23.9 inches between 3 and 9 o'clock orientations, indicating some ovality. The diameters of the D/S joint were both 24.1 inches, indicating no measurable ovality, as shown in Table 1. The diameters meet API 5LX tolerances[2] for 24-inch nominal diameter pipe.

Wall thicknesses were measured at the 12, 3, 6, and 9 o'clock orientations at areas with negligible corrosion and no coating near the failure location, at the U/S and D/S ends of the failed joint, on the U/S joint, and on the D/S joint; see Table 2 for details. The wall thickness values ranged between 0.272 inches and 0.296 inches, with the exception of the area immediately adjacent to the failure at the 3 o'clock orientation, where the wall thickness was 0.251 inches due to local yielding (necking) at the rupture area. The average wall thickness of the ruptured joint, U/S joint, and D/S joint are 0.276 inches (excluding the failure area), 0.288 inches, and 0.282 inches, respectively. The average wall thickness values and the individual wall thickness values away from the rupture area meet API 5LX tolerances for a nominal wall thickness of 0.260 inches.

Table 3 contains a summary listing of the various features found on the pipe section, as described further in the text below, together with the locations from which cross-section samples ("Mounts") were prepared, as described in Sections 3.3 and 3.4. The rupture was 3.77 feet in length, consisting of a symmetric fish-mouth failure that initiated at or near the toe of the DSAW at the 3:26 o'clock orientation, on the clockwise (CW) side of the seam weld. The U/S and D/S ends of the rupture were located at 14.17 feet and 17.94 feet, respectively, from the U/S GW as shown in Figure 3. The maximum opening was 4.5 inches (0.38 feet), approximately 16.13 feet from the U/S GW.

The crack path was relatively smooth in appearance, located at the toe of the DSAW for approximately 7 inches (15.88 – 16.46 feet from U/S GW) of the rupture length, and then transitioning off of the toe in either direction, upstream and downstream. The coating on either side of the fracture, within 1-3 inches, was locally disbonded; however, the coating on the remaining portions of the pipe section was in good condition and well adhered to the pipe steel. There was no evidence of external corrosion along the areas of disbonded

2 API 5LX (23rd Ed., March 1980): "Out-of-Roundness. For pipe larger than 20 in., and for a distance of 4 in. (101.6 mm) from the ends of the pipe, the maximum outside diameter shall not be more than 1 per cent larger than specified, and the minimum outside diameter shall not be more than 1 per cent smaller than specified."

coating, suggesting that the local disbondment was a result of plastic deformation of the pipe material during the rupture event.

3.2 Magnetic Particle Inspection

The pipe section was cut longitudinally to facilitate examination of the internal surfaces and MPI of the longitudinal seam welds of the failed joint and U/S and D/S joints. There was no evidence of internal corrosion. Two areas with indications were identified along the internal surface of the failed joint at the toe of the seam weld. A summary of the locations and dimensions of these indications is presented in Table 4.

Area 1 included MPI Indication 1a (CW) and MPI Indication 1b (CCW), both located approximately 2.7 feet D/S of the rupture origin (~18.8 feet from U/S GW), see photograph in Figure 4. The indications appear as crack-like features along the toe of the seam weld. MPI Indication 1a appears as a crack-like feature between 18.62-19.05 feet from the U/S GW, at the weld toe on the CW side of the seam weld. MPI Indication 1b also appears as a crack-like feature, and is located between 18.70-19.12 feet from the U/S GW, at the weld toe on the CCW side of the seam weld. Two 3/8 inch long areas of weld overlap are also apparent 18.8 ft from the U/S GW.

Area 2 contains MPI Indication 2 (CW), located 7.7 feet D/S of the rupture (23.83 feet from the U/S GW), see photograph in Figure 5. The indication appears as a small (0.25 inch long) dimple of missing weld metal (undercut), resulting in a notch at the toe of the seam weld.

3.3 Fractographic Examination

3.3.1 Rupture Location

Figure 6 is a photograph of the CW side of the fracture surface of the rupture before cleaning. A flaw originating from the pipe inside (ID) surface is evident on the fracture surface 15.88-16.46 ft from the U/S GW. That area (CW side only) was cut out and cleaned with a degreaser and methanol. Figure 7 shows a photo-collage of the suspected rupture origin after cleaning. The surface is dull and gray in color, with slightly lighter areas near the internal surface. The pre-existing flaw at the ID surface has a semi-elliptical shape, with the suspected rupture origin located at approximately 16.13 ft from the U/S GW. The origin location was identified based on the overall flaw shape and fracture surface coloration.

The fracture surface was categorized into three regions: **Region 1** – flat, slightly lighter gray in appearance, located near the internal surface, and perpendicular to the internal and external surfaces; **Region 2** – rough in texture, darker gray in appearance, located near mid-wall, and perpendicular to the internal and external surfaces; **Region 3** – rough in texture, darkest gray in appearance, located near the external surface, and at an oblique angle with respect to the internal and external surfaces. The pre-existing (prior to failure) flaw consists of Region 1 and Region 2.

These three regions are shown in the optical photomicrograph in Figure 8, taken approximately 16.1 feet from the U/S GW. Region 1 contains multiple crack fronts on various planes that are separated by ratchet marks[3]. This macro-scale morphology is consistent with multiple crack initiation sites. At higher magnification, Figure 9, small pits can be seen along the internal surface, possibly serving as crack initiation sites. These pits might have formed during the long storage period of the line pipe prior to construction or could have formed in service.

Region 2 and Region 3 are macroscopically rougher than Region 1. The oblique angle of Region 3 with respect to the internal and external pipe surfaces is consistent with a shear lip, indicative of ductile overload. Except for the discoloration in the described regions, the fracture surface did not have distinct beach marks[4], which are commonly associated with the growth of a fatigue crack.

Figure 10 is an SEM image of an area of the fracture surface from within the suspected failure origin, approximately 16.1 feet from the U/S GW. The orange dashed lines indicate the interfaces between Regions 1/Region 2, and Region 2/Region 3. Note the rough woody morphology of Region 2.

Figure 11 is an SEM image of the fracture surface within Region 1. Large steps and cracks are visible parallel to the ID pipe surface. Figure 12 is a higher magnification SEM image of the fracture surface immediately adjacent to the ID pipe surface, where a pit of approximately 100 microns wide by 50 microns deep is visible, similar to the pits discussed in the optical photomicrograph in Figure 9. Figure 13 shows another high magnification SEM photomicrograph taken within Region 1 adjacent to the internal surface. The image shows fatigue striations[5] that emanate from the internal surface. Figure 14 is an SEM image of the fracture surface within Region 2. A stair-stepped, "woody" topography with little evidence of ductility was evident through much of Region 2, which can be indicative of

3 Ratchet marks: Macroscopic features that originate when multiple cracks, nucleated at different points, join together, creating steps on the fracture surface.

4 Beach marks: Macroscopic concentric marks that are a result of successive arrests or decrease in the rate of fatigue crack growth due to a temporary load drop, or due to an overload that introduces a compressive residual stress field ahead of the crack tip.

5 Fatigue striations: Microscopic features (that may be) visible with the aid of a scanning electron microscope, resulting from the successive blunting and re-sharpening of the crack tip in ductile materials, and that appear as fine, parallel lines perpendicular to the direction of crack growth.

intermittent crack growth. Some secondary cracking is also visible, possibly related to the different microstructure of the weld HAZ near mid-wall, or related to an environmental effect on crack growth that caused crack branching. At higher magnification, the morphology consisted of bands of ductile overload separated by bands that exhibited little to no cohesion with the surrounding material, and secondary cracking; refer to Figure 15. Figure 16 and Figure 17 are SEM images confirming ductile overload failure in Region 3.

Figure 18 and Figure 19 show detailed flaw depth measurements taken of Region 1 and Region 2 on the CW side fracture surface. Wall thickness measurements were also taken along the fracture surface, and the measurements ranged between 0.226 and 0.251 inches, showing that the metal in the rupture area yielded from its nominal wall thickness of 0.260 inches. Figure 20 is a plot of flaw depth versus distance from the U/S GW. The measured flaw associated with Region 1 is indicated by the red line, while Region 2 is indicated by the green line. The figure shows that the pre-existing (prior to rupture) flaw length was approximately 7.0 inches, and that the maximum depth of Region 1 is 0.097 inches and the maximum depth of the combined flaw (Region 1 + Region 2) is 0.210 inches; 37.3% and 80.8% of the 0.260 inches nominal wall thickness, respectively.

3.3.2 Testing for Sulfides and Carbonates – Primary Fracture Surface

Spot testing, using a 1M HCl solution, was performed on the CCW side of the fracture surface (no cleaning) to test for the presence of sulfides and carbonates. A color change from white to brown in lead-acetate test paper is a positive indicator of sulfides, while vigorous bubbling is a positive indicator for carbonates. The fracture surface tested positive for the presence of sulfides and negative for carbonates. The sulfides likely deposited on the fracture surface by a corrosion mechanism and might have played a role in the fatigue crack growth. The absence of carbonates indicates that CO_2 likely did not play a role in the corrosion process.

3.3.3 MPI Indications

Prior to breaking open MPI Indication 1a, a piece was removed from its center for cross-section metallography (Mount 1), which is described later. After that, the remaining U/S and D/S portions of the pipe piece containing MPI Indication 1a were submerged in liquid nitrogen and struck with a brass mallet to break open the flaw for fractographic examination. The created fracture was not cleaned. Figure 21 is a photograph of the flaw that (after removing the metallographic section) measured approximately 4.25 inches in length. Figure 22 is a close-up view of the center portion of the flaw, showing the maximum depth is approximately 0.125 inches (48.1% of 0.260 inches nominal wall thickness). The flaw has a dark appearance and a staggered fracture path on multiple parallel planes.

Figure 23 is a close-up view of the flaw, which has two distinct colored regions, a black region (Region 1) adjacent to the pipe ID surface and a brown region (Region 2) near mid-wall. The black Region 1 is located adjacent to the internal surface and resembles Region 1 of the pre-existing flaw located at the rupture origin, as described above, with an overall relatively flat appearance and ratchet marks along the ID to indicate multiple initiation planes. White residue from the MPI testing is present in Region 1, indicating that the crack was open to the ID surface of the pipe prior to fracture. The brown Region 2 resembles Region 2, with a stair-stepped, "woody" fracture appearance. Oily residue is present in both Regions A and B, showing that both regions were present during service when crude oil could leach in.

MPI Indication 1b and MPI Indication 2 were not broken open, because the metallographic cross-sections showed no cracks were present, as will be discussed in Section 3.4.3.

3.3.4 Testing for Sulfides and Carbonates – MPI Indication 1a

Spot testing, using a 1M HCl solution, was performed on the CCW side of the fracture surface (no cleaning) to test for the presence of sulfides and carbonates. The fracture surface tested positive for the presence of sulfides and negative for carbonates.

3.4 Metallographic Examination

This section describes the observations from metallographic cross-section samples taken from the rupture origin location (Mount M5 and Mount M6), from reference locations (Mount M7, Mount M3, and Mount M4), and from MPI Indications (Mount M1 and Mount M2), as summarized in Table 6 and shown in Figure 1.

3.4.1 Rupture Origin

Figure 24 and Figure 25 are photographs of transverse metallographic sections (Mount M5 and Mount M6) that were removed from across the fracture surface at approximately 16.13 feet and 16.33 feet from the U/S GW, respectively. Mount M5 was removed from the likely rupture origin, and Mount M6 was removed 2.4 inches (0.2 feet) D/S of the likely rupture origin. The locations are shown in Figure 1 and Figure 6. The morphology of the weld is consistent with DSAW with the final pass at the OD pipe surface.

Figure 26 shows typical examples of the microstructures of the base metal (Figure 26a), the weld fusion metal near the ID surface (Figure 26b), the HAZ metal near the ID weld toe that failed (Figure 26c), and the HAZ metal near mid-wall (Figure 26d). The base metal consists of equi-axed ferrite (white grains) and pearlite (black grains) and, within that structure, some rounded and elongated inclusions are present. This microstructure is consistent with the vintage and grade of the steel. The weld fusion metal of the weld bead at the ID pipe surface also has equi-axed grains, but contains visually more ferrite than the pipe base metal. The microstructure of the HAZ near the ID weld toe shows angular grain morphology, known as Widmanstätten structure. At the mid-wall of the pipe wall thickness, the HAZ consists of ferrite and pearlite with a finer grain size than the base metal. These microstructures are all typical of DSAW welds in carbon steel line pipe.

Both mounts appear very similar, with the inside and outside weld passes located on the center of the bond line (not offset laterally[6] from one another), and with the primary crack extending from the CW toe on the internal surface through the HAZ of the weld to the OD pipe surface near the weld toe. Note that the crack at the OD pipe surface in both mounts is at an oblique angle with respect to the pipe surface, which is consistent with final failure by ductile shear. In both mounts, the weld appears to be peaked or tented as a result of the approach angle between the CW and CCW plate edges; further discussion is provided in Section 3.4.6.

Figure 27 and Figure 28 are montages of photomicrographs showing the cross-section through the fracture surfaces on the CW side of the seam weld of Mount M5 (failure origin) and Mount M6, respectively. Mount M6 revealed similar features as Mount M5, and is therefore not separately discussed further here. Both cross-sections show that the fracture plane is radial[7] through 70%-80% of the wall thickness and then transitions to a 45 degrees angle near the OD pipe surface. The 45 degree angle is consistent with a shear lip, associated with ductile overload, and correlates with Region 3 previously defined above. Region 2 is rougher than Region 1 or Region 3 and some secondary cracks are present in Region 2. As mentioned earlier, crack branching at the pipe mid-wall (rougher Region 2) may be a result of microstructural differences in the weld and/or an environmental effect.

Figure 29 is a photomicrograph showing the location of fracture initiation at the immediate edge of the internal weld bead and the HAZ. The fracture path is straight, consistent with fatigue identified in Region 1 in the SEM examination.

Figure 30 is a photomicrograph showing the rough fracture path consistent with the step-wise characteristics of Region 2 identified during the SEM examination. Secondary cracks are present along the fracture surface in this region. The secondary cracks are relatively straight.

6 "Out-of line weld bead (off-seam weld) shall not be cause for rejection provided complete penetration and complete fusion have been achieved as indicated by nondestructive examination." API 5LX, 23rd Edition, 1980.

7 Approximately perpendicular to the pipe walls.

Figure 31 is a photomicrograph from the area identified as Region 3, showing elongated and deformed grains in the 45 degree plane, which is consistent with shear ductile overload.

Figure 32 shows photomicrographs in the as-polished and as-etched conditions of an area on the ID surface of Mount M5, in the base metal away from the rupture area. A micro-pit (100-200 micron size) filled with corrosion product is visible. This particular corrosion product was not analyzed for composition, but EDS analyses of other scales indicate it is likely a Fe-O-S compound; refer to Section 3.4.4. This image is a typical example of several micro-pits that were observed in the cross-sections. No cracking was associated with this or other micro-pits visible in the base metal areas of the cross-sections.

Figure 33 is a montage of photomicrographs of the CCW side of the weld in Mount M6 (opposite side of the weld at the rupture location). A small crack is apparent from the weld toe into the HAZ. Two similar cracks are present at the toe of the seam weld on the CCW side in Mount M5, and Figure 34 shows photographs of these cracks in the as-polished and as-etched conditions. The cracks in Mounts M5 and M6 are approximately 200 microns deep, which is consistent with them being continuous along the seam weld and being only 2.4 inches apart. The cracks originate from the pipe ID surface, each in an area with a micro-pit that is filled with corrosion product. As previously discussed, these pits might have formed during the long storage period of the line pipe prior to construction or could have formed in service. Both cracks are branched and have a transgranular crack path into the HAZ. The presence of corrosion products and crack branching are characteristics that may be associated with an environmental degradation mechanism.

3.4.2 Reference Locations

Metallurgical cross-sections were removed from across the seam weld of the failed pipe joint (away from the rupture; Mount M7), the U/S joint (Mount M4), the D/S joint (Mount M3). Photographs of the mounted cross-sections are presented in Figure 35, Figure 36, and Figure 37, respectively. There was no evidence of cracking in the welds or base metal in any of these reference mounts.

3.4.3 MPI Indications

Figure 38 and Figure 39 are photographs of the metallographic cross-sections, Mount M1 and Mount M2, respectively, removed from the locations marked in Figure 4 (MPI Indications 1a/1b and Figure 5 (MPI Indication 2).

Figure 40 is a photomicrograph of the area associated with MPI Indication 1a. At this location, a crack from the ID pipe surface, at the CW side of the seam weld, is present with a depth of approximately 0.119 inches (45.8% of 0.260 inches nominal wall thickness). The crack path close to the ID surface is straight without crack branching (refer back to Region 1 in Figure 23), and, further into the metal, transitions to a tortuous path where crack branching is apparent (refer back to Region 2 in Figure 23). Figure 41 shows a higher magnification photomicrograph of the crack tip, where extensive crack branching is apparent in the fine-grain microstructure of the HAZ. The inset photo in this figure shows a close-up view of the transgranular morphology (red circles) at the crack tip.

Figure 42 is a photomicrograph of the area associated with MPI Indication 1b. At this location, weld overlap is apparent. The filler metal of the weld bead extends approximately 3 mm (3000 microns) over the pipe ID surface on the CCW side of the seam weld. While the overlap creates a sharp transition at the weld toe, no cracking is apparent at the tip of that transition.

Figure 43 is a montage of photomicrographs of the area associate with MPI Indication 2. A notch of approximately 0.060 inches depth (23.1% of 0.260 inches) nominal wall thickness) is present where weld undercut has occurred. Figure 44 shows photomicrographs, in the as-polished and as-etched condition, of a 0.012 inches deep crack (4.6% of 0.260 inches nominal wall thickness) that initiated from this notch. Similar to the cracks found at the seam weld toe on the CCW side of Mount M5 and Mount M6 at the rupture location, the crack at MPI Indication 2 initiated from a micro-pit that is filled with corrosion product (which was not removed during the cleaning process of the sample preparation). The crack morphology is transgranular and branching that extends into the HAZ microstructure suggests an environmental damage mechanism.

3.4.4 EDS Analysis of Cracks and Corrosion Products

Scanning electron microscopy with EDS was performed on the metallographically prepared cross-sections of the crack associated with MPI Indication 1a (Mount M1) and the crack and pit with corrosion products associated with MPI Indication 2 (Mount M2), to analyze for the presence of sulfur and other elements.

Figure 45 shows a composition SEM/EDS image of the crack tip associated with MPI Indication 1a, where the green color indicates areas where sulfur was detected. In this figure, approximately one-third of the crack depth is visible. The imaged crack tip is approximately 0.043 inches (1100 microns) of the overall crack depth of 0.119 inches. On Mount M1, no EDS analysis was performed in the area of the crack mouth near the inside pipe surface.

Figure 46 shows EDS elemental maps for the elements iron (Fe), oxygen (O), manganese (Mn), sulfur (S), silicon (Si), and carbon (C). These images reveal that oxygen- and sulfur-containing corrosion products are present within the crack, all the way to the tip of the crack. The likely source of the elements sulfur and oxygen is the crude oil in the pipeline. Other detected sulfur within the HAZ metal coincides with inclusions visible in the cross-section and also with manganese in the elemental maps, thus indicating that those inclusions are most likely MnS compounds.

Figure 47 shows the locations where EDS analyses were performed of the corrosion product and base metal at the ID surface of MPI Indication 2. The results are summarized in Table 5, revealing that the corrosion product has high concentrations of sulfur (27-32 wt.%), some oxygen (7-11 wt.%), with the balance predominantly iron (55-65 wt.%) (EDS #1, EDS #2, and EDS #3) when compared with the base metal (EDS#4).

Figure 48 shows a composition SEM/EDS image and Figure 49 shows EDS elemental maps of the corrosion-filled pit at the notch and the crack located at the CCW toe of the weld at the ID pipe surface. Sulfur was detected in the corrosion product, inside the crack along the entire crack path, and MnS inclusions were located within the metal. As with the previous MPI indication, the presence of sulfur suggests an environmental component to the damage mechanism.

3.4.5 Hardness Testing

Vickers micro-hardness testing was performed, using a 500 g load, on Mounts M5 and M6 (rupture), Mounts M3, M4 and M7 (D/S, U/S, and failed joints), Mount M1 (MPI Indications 1a/1b) and Mount M2 (MPI Indication 2). The test locations and results are summarized in Figure 50, in Figure 51, Figure 52, and Figure 53, respectively.

For the ruptured area of the failed joint, the hardnesses in the HAZ on the CW side of the seam weld, adjacent to Region 1 and Region 2 (Locations 1, 2, 3, 4, 5, 8) were measured. The hardness values ranged between 190.3 and 218.1 HV (Mount M5) and 183.4 and 218.8 HV (Mount M6). The maximum hardness measured was in the base metal of Mount M5, 227.8 HV. 225.0 HV (HAZ in Mount M7), 235.1 HV (weld metal, Mount M4), 213.5 HV (weld metal, Mount M3), were the maximum values measured for the three joints.

The range of hardness measured on the failed side of the weld was very similar to those measured on the unfailed side of the weld. The hardness values measured on the unfailed welds were similar to those measured in the failed welds. The hardness values near the

MPI Indications were similar to those in weld areas without MPI Indications. All these observations show that hardness was not a contributing factor to the failure.

International standards[8] provide guidance for the application of materials exposed to service conditions that promote sulfide stress cracking (SSC). All of the measured values are less than the maximum allowable hardness of 250 HV for weld roots, base metal, and HAZ. Therefore, any environmental component to crack growth is more likely related to corrosion fatigue than SSC.

3.4.6 DSAW Measurements

The cross-sections removed from the ruptured joint exhibited a slightly more peaked appearance than those in the U/S and D/S joints. This is a local discontinuity to the roundness of the pipe that can not only affect how the sensors of an ILI tool contact the pipe, but also how stresses in the pipe develop when it is pressurized. Under normal operation, the internal pressure of the pipe will strain the pipe to a rounded condition, generating an additional tensile bending stress at the internal surface. This, in combination with the geometry of the weld toe, can produce locally high stresses.

Measurements were made on Mounts M1-M7 to quantify the angle between the plate edges on the CW and CCW sides of the seam weld. The lower the angle (farther away from the ideal 180°), the higher the tensile bending stress when the pipe is pressurized. The results are summarized in Table 6, with additional photographs provided in Appendix A. To visualize any peaking at the weld, the inside and outside pipe diameters for a perfectly round cylinder are drawn in the Figures A1 through A7. API 5LX (1980) does not include requirements for the allowable angle between plate edges.

To estimate the original geometry for Mount M5 and Mount M6 prior to rupture, the CW fracture surface for each mount was rotated until the fatigue regions (Region 1) of the mating faces were parallel. The angles measured on the failed joint ranged between 161 degrees at the rupture origin (Mount M5) and 165 degrees at MPI Indication 2 (Mount M2) with the other mounts having values in between. The angle at the reference locations on the adjacent joints was higher with 167 degrees on the D/S joint (Mount M3), and 169 degrees on the U/S joint (Mount M4).

8 ANSI/NACE MR0175/ISO 15156-2:2015, Petroleum, petrochemical and natural gas industries —Materials for use in H_2S-containing environments in oil and gas production — Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons.

3.5 Mechanical Testing

The results of tensile testing of duplicate, transverse base metal and seam weld specimens removed from the pipe joint that ruptured are shown in Table 7. The average yield strength (YS) and ultimate tensile strength (UTS) of the base metal were 70.3 ksi and 87.8 ksi, respectively. The average YS and UTS of the base metal samples meet the minimum YS and UTS requirements for API 5LX Grade X60 line pipe steel of 60.0 ksi and 75.0 ksi, respectively.[9] The average UTS of duplicate transverse samples removed from the longitudinal seam weld was 85.7 ksi, which exceeds the minimum UTS requirement for API 5LX Grade X60 line pipe steel of 75.0 ksi. YS values across welds are not specified in API 5LX.

The results of tensile testing of transverse base metal specimens removed from the U/S and D/S joints are shown in Table 8. The specimens meet the minimum YS and UTS requirements for API 5LX Grade X60 line pipe steel of 60 ksi and 75.0 ksi, respectively.

Table 9 and Table 10 summarize the results of the Charpy testing for the transverse base metal and seam weld samples removed from the failure joint while Figure 54 through Figure 57 show the Charpy percent shear and impact energy curves. An analysis of the data for the base metal specimens indicates that the 85% fracture appearance transition temperature (FATT) is 10.8°F and the upper shelf Charpy energy is 31.7-ft·lbs, full size. These results are typical for this vintage and grade of line pipe steel.

The CVN test results can be adjusted to determine the 85% FATT that would be expected for full-scale pipe by applying temperature shifts to the data. This method (full-scale) adjusts the 85% FATT obtained from the Charpy tests to a predicted FATT from the Battelle Drop-Weight Tear Test (BDWTT). The predicted 85% FATT from the BDWTT test most closely represents the expected FATT for full-scale pipe wall material.[10] The full-scale brittle to ductile transition temperatures for the samples, based on a nominal pipe wall thickness of 0.260 inches, are shown in Table 11. The base metal is expected to exhibit ductile fracture behavior above 0.2°F.[11]

Similarly, the data for the seam weld (HAZ) specimens indicates that the 85% FATT is -62.1°F and the upper shelf Charpy energy is 34.0 ft·lbs, full size. The seam weld (HAZ) is expected to exhibit ductile fracture behavior above -63.6°F, refer to Table 11.

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9 API 5LX, 23rd Edition, 1980.

10 W. A. Maxey, J. F. Kiefner, R. J. Eiber, *Brittle Fracture Arrest in Gas Pipelines,"* NG-18 Report No. 135, A.G.A. Catalog No. L51436, April 1983, Battelle Columbus Laboratories.

11 Rosenfeld, M.J., *"A Simple Procedure for Synthesizing Charpy Impact Energy Transition Curves from Limited Test Data,"* International Pipeline Conference, Volume 1, ASME, 1996, Equation 1.

3.6 Chemical Analysis

The results of the chemical analysis performed on samples removed from the pipe joint that ruptured and the U/S and D/S joints are shown in Table 12. All three joints meet the composition requirements for API 5LX Grade X60 for this vintage.

3.7 Failure Pressure Analysis

CorLAS™ was used to estimate the failure pressure for the following cases:

- Case 1: Measured mechanical base-metal properties, measured pipe dimensions, and the as-measured flaw profile of Region 1 (Fatigue).
- Case 2: Measured mechanical base-metal properties, measured pipe dimensions, and the as-measured flaw profile of Region 1 (Fatigue) + Region 2 (Possible Environmental Cracking).
- Case 3: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue).
- Case 4: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue) + Region 2 (Possible Environmental Cracking).

The results of the analyses are shown in Table 13. The calculated failure pressure, incorporating the base-metal properties, for Case 1 and Case 2 are 1413 psig and 658 psig, respectively. Similar results were obtained using the mechanical properties of the HAZ, which resulted in calculated failure pressures of 1394 psig and 664 psig for Case 3 and Case 4, respectively. Additional details of the analyses, and a description of CorLAS™, are summarized in Appendix B.

Using the provided discharge pressure at Tracy pump station (694 psig) and suction pressure at Marsh Creek pump station (364.6 psig) at the time of failure, the pressure at the failure location was calculated from provided elevation data. The elevation of the failure location was estimated to be 365 feet, resulting in a calculated pressure of 665 psig.[12] By incorporating the flaw profile of Region 2 (Case 2 and Case 4), the estimated failure pressure is in good agreement with the calculated pressure at the location and time of failure.

12 Stationing data was not available, so the failure location was estimated to be 0.5 miles downstream of the Tracy pump station.

4.0 CONCLUSIONS

The results of the metallurgical analysis indicate that the pipe joint ruptured at a fatigue crack that initiated at the toe of the DSAW seam weld on the inside surface of the pipe. Likely contributing factors include the peaked geometry of the failed pipe joint at the seam weld that introduced a bending stress, corrosion micro-pits on the ID surface that provided initiation sites, aggressive pressure cycling of the pipeline, and possibly an environmental effect on crack growth.

The fatigue crack initiation and propagation most likely occurred while in service. However, transit fatigue during transportation of the pipe cannot be ruled out as a contributing factor. Shell reported to have records of rail transportation per API 5L1,[13] for the first portion of the journey, from Houston Texas to the northeast of the U.S. For the second portion of the journey, from the northeast to Coalinga California, verbal information indicates that API 5L1 would have been specified per industry norms, but written records have not been located.

Summary of observations:

- The pipe joint that ruptured contained several types of mill anomalies at the long seam weld, including peaking, weld overlap[14], and weld undercut[15].
- The fatigue crack at the rupture origin was 6.96 inches long and initiated from small (50-100 micron) pits along the internal toe of the DSAW. There was no evidence of a pre-existing weld-type defect at this location. The long-seam weld was located at the 3:26 o'clock orientation.
- The fracture surfaces consisted of three regions:
    - **Region 1** – a crack region at the internal surface with a maximum depth of 0.097 inches (37.3% of 0.260 inches nominal wall thickness) caused by fatigue;
    - **Region 2** – a crack region with a stair-stepped appearance, beginning at the end of Region 1, resulting from higher stress intensity factor at the crack tip as the crack propagated deeper into the material and possibly an environmental component. The maximum depth of this region is 0.210 inches (80.8% of 0.260 inches nominal wall thickness);
    - **Region 3** – the remaining ligament that overloaded during the rupture event.
- MPI testing revealed other crack-like flaws on the pipe joint that failed, at approximately 2.7 feet D/S and 7.7 feet D/S of the rupture origin along the internal

13 API RP 5L1, Recommended Practice for Railroad Transportation of Line Pipe.

14 Weld overlap is an imperfection at the toe or root of a weld caused by metal flowing onto the surface of the parent metal without fusing to it. It may occur in both fillet and butt welds.

15 Weld undercut is an irregular groove at the toe of a weld run in the parent metal. A common cause of undercut is a wide spreading arc (high arc voltage) with insufficient fill (low current or high travel speed).

surface of the DSAW. The largest feature (MPI Indication 1a) was 4.25 inches in length and 0.125 inches depth (48.1% of 0.260 inches nominal wall thickness) at the deepest location.

- Qualitative spot testing indicated the presence of sulfides on the fracture surface at the failure origin, which is not uncommon in crude oil pipelines.
- Cross-sections showed that cracks at weld toes at locations away from the rupture were filled with sulfur-containing products, which is not uncommon in crude oil pipelines.
- There was no evidence of external corrosion on the pipe section.
- No MPI indications were identified on portions of the longitudinal seam weld of the U/S or D/S joints that were examined; 1.58 feet of the U/S joint and 1.79 feet of the D/S joint.
- The tensile properties of the failed joint and the joints U/S and D/S of the failed joint meet the tensile requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The Charpy V-notch (CVN) properties of the base metal of the failed joint are typical for the vintage and grade of line pipe steel. The seam weld HAZ had better fracture toughness properties than the base metal, with a slightly higher upper shelf impact energy and lower 85% FATT temperature.
- The composition of the base metal of the failed joint and the joints U/S and D/S of the failed joint meets requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The microstructures of the pipe joints are typical for the vintage and grade of line pipe steel.
- The estimated failure pressure using mechanical properties of the heat affected zone and the flaw profile that ruptured for Region 1 + Region 2 is 664 psig, which is close to the calculated pressure at the failure location and time of failure (665 psig).

Table 1. Results of diameter measurements performed on the U/S and D/S joints, adjacent to the failed pipe joint.

Location	Diameter (inches)	
	12 to 6 o'clock [1]	3 to 9 o'clock [1]
U/S end of U/S Joint	24.2	23.9
D/S end of D/S Joint	24.1	24.1

1 – Measurements exclude coating thickness.

Table 2. Results of wall thickness measurements performed on the U/S, D/S, and failed pipe joints in areas with negligible corrosion and no coating.

O'clock Orientations	Wall Thickness (inches)				
	U/S End of U/S Joint [4]	U/S End of Ruptured Joint	Near Failure Location in Ruptured Joint	D/S End of Ruptured Joint	D/S End of D/S Joint
12:00	0.279	0.277	0.278	0.278	0.295
3:00	0.296	0.274	0.251 [1]	0.273 [2]	0.295
6:00	0.289	0.272	0.278	0.278	0.267
9:00	0.289	0.273	0.276	0.276	0.272
Average	0.288	0.274	N/A [3]	0.276	0.282

1 – Measurements taken near Mount M5 location, CCW side of the seam weld.
2 – Measurement average near Mount M2 and Mount M7, CCW side of the seam weld.
3 – Average not applicable, because of yielding near rupture opening.
4 – This is 1.58 feet U/S of the D/S end of the U/S joint.

Table 3. Summary of locations of metallurgical mounts and other features on the received pipe section.

Location	Cross-Section	Distance from U/S GW (feet)
End of U/S Pipe Section	–	-1.58
U/S Girth Weld	–	0.00
U/S Joint	Mount M4	-1.54
U/S End of Rupture Opening	–	14.17
U/S End of Pre-Existing ID Flaw	–	15.88
Section through Rupture Origin	Mount M5	16.13
Section through Rupture	Mount M6	16.33
D/S End of Pre-Existing ID Flaw	–	16.46
D/S End of Rupture Opening	–	17.94
U/S End of MPI Indication 1a (CW)	–	18.62
U/S End of MPI Indication 1b (CCW)	–	18.70
Section through MPI 1a and 1b	Mount M1	18.81
D/S End of MPI Indication 1a (CW)	–	19.05
D/S End of MPI Indication 1b (CCW)	–	19.12
Failed Joint, Away from Rupture	Mount M7	21.16
MPI Indication 2	Mount M2	23.83
D/S Girth Weld	–	26.44
D/S Joint	Mount M3	28.19
End of D/S Pipe Section	–	28.23

Table 4. Summary of the locations and dimensions of indications identified on the internal surface of failed joint by magnetic particle inspection.

MPI Indication	Distance [2] from U/S GW (feet)	Axial Length (inches)	O'clock Orientation	Depth [1] (inches)
Indication 1a Crack-like indication on ID surface. At HAZ on CW side of seam weld	18.62	5.6	3:26	0.119 Crack at CW side
Indication 1b Crack-like indication with weld overlap on ID surface. At HAZ on CCW side of seam weld	18.70	0.35	3:26	0.000 No crack under overlap
Indication 2 Notch (weld undercut) on ID surface. At HAZ on CW side of seam	23.83	0.02	3:26	0.060 Notch at HAZ 0.011 Crack from notch

1 – Measurements made on metallographic cross-sections.

2 – Distance indicates U/S end of the indication.

Table 5. Results of EDS analyses (in wt.%) performed on corrosion products remaining within corrosion pits at weld toe on the internal pipe surface of Mount M2. Refer to Figure 47 for analysis locations.

Spectrum		EDS #1	EDS #2	EDS #3	EDS #4
Carbon	**(C)**	–	–	–	–
Oxygen	**(O)**	8	11.4	7	5.4
Sodium	**(Na)**	–	–	–	–
Aluminum	**(Al)**	–	0.1	–	1.7
Silicon	**(Si)**	0.1	0.4	0.1	0.5
Phosphorous	**(P)**	–	–	–	0.1
Sulfur	**(S)**	32.3	31.6	27.0	0.1
Calcium	**(Ca)**	0.2	0.3	0.2	0.1
Chromium	**(Cr)**	–	–	–	0.1
Manganese	**(Mn)**	–	0.6	0.4	0.9
Copper	**(Cu**	–	–	–	0.2
Iron	**(Fe)**	59.4	55.7	65.3	91

Table 6. Results of measurements performed on Mounts M1-M7 to determine the angle between the plate edges on the CCW and CW sides of the seam weld. Refer to Appendix A for additional details.

Mount №	Location	Angle Between CW and CCW Sides (Degrees)
Mount M1	MPI Indications 1a / 1b	162
Mount M2	MPI Indication 2	165
Mount M3	D/S Joint	167
Mount M4	U/S Joint	169
Mount M5	Section Through Rupture Origin	161
Mount M6	Section Through Rupture	163
Mount M7	Failed Joint, Away from Rupture	165

Table 7. Results of tensile tests performed on transverse base metal and weld (HAZ) specimens from the joint that ruptured compared with requirements for API 5LX Grade X60 line pipe steel.[2]

	Base Metal	Seam Weld	API 5LX Grade X60 (Minimum Values) [2]
Yield Strength, ksi [1]	*70.3*	–	*60.0*
Tensile Strength, ksi [1]	*87.8*	*85.7*	*75.0*
Elongation in 2 inches, % [1]	*26.0*	–	*20.6*
Reduction of Area, % [1]	*33.7*	*32.7*	–

1 – Average of duplicate tests.
2 – API 5LX, 23rd Edition, 1980.

Table 8. Results of tensile tests performed on transverse base metal specimens from the U/S and D/S joints compared with requirements for API 5LX Grade X60 line pipe steel.[2]

	U/S Base Metal	D/S Base Metal	API 5LX Grade X60 (Minimum Values) [2]
Yield Strength, ksi [1]	*77.7*	*71.2*	*60.0*
Tensile Strength, ksi [1]	*95.6*	*86.8*	*75.0*
Elongation in 2 inches, % [1]	*22.7*	*27.2*	*20.6*
Reduction of Area, % [1]	*29.1*	*33.3*	–

1 – Average of duplicate tests.
2 – API 5LX, 23rd Edition, 1980.

Table 9. Results of Charpy V-notch impact tests performed on transverse base metal specimens removed from the joint that ruptured.

Sample ID	Temperature, °F	Sub-Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, inches
A-10	-60	6	11	5	0.006
A-6	-45	5	9	10	0.011
A-9	-30	7	12	35	0.012
A-5	-20	7	12	35	0.017
A-8	-10	7	12	35	0.013
A-7	0	11	19	80	0.020
A-4	5	15	26	90	0.028
A-3	30	16	28	95	0.031
A-2	55	20	35	100	0.034
A-1	80	18	32	100	0.034

Table 10. Results of Charpy V-notch impact tests performed on transverse seam weld (HAZ) specimens removed from the joint that ruptured.

Sample ID	Temperature, °F	Sub-Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, inches
B-10	-100	6	12	0	0.012
B-9	-80	6	11	5	0.011
B-8	-60	12	24	95	0.029
B-6	-45	14	28	95	0.026
B-7	-30	15	30	100	0.028
B-5	-20	15	30	100	0.027
B-4	5	15	30	100	0.027
B-3	30	17	33	100	0.029
B-2	55	16	32	100	0.035
B-1	80	18	36	100	0.037

Table 11. Results of analyses of the Charpy V-notch impact energy and percent shear plots for base metal and seam weld (HAZ) specimens removed from the joint that ruptured.

	Base Metal	Seam Weld (HAZ)
Upper Shelf Impact Energy (Full Size), Ft-lbs	31.7	34.0
85% FATT, °F	10.8	-62.1
85% FATT, °F (Full Scale Pipe) [1]	0.2	-63.6

1 – Full Scale Pipe FATT = 85% FATT + $((66*(t_w^{0.55}/t_c^{0.7})-100)$ where t_w = pipe wall thickness and t_c = width of the CVN specimen.

Table 12. Results of chemical analyses performed on samples removed from the joint that ruptured and the U/S and D/S joints compared with composition requirements for API 5LX Grade X60 line pipe steel.[1]

Element		Composition, Joint That Ruptured (Wt. %)	Composition, U/S Joint (Wt. %)	Composition, D/S Joint (Wt. %)	API 5LX Grade X60 Spec (Wt. %) [1]
C	(Carbon)	0.158	0.174	0.160	0.29 (max)
Mn	(Manganese)	1.23	1.40	1.32	1.45 (max)
P	(Phosphorus)	0.010	0.024	0.008	0.05 (max)
S	(Sulfur)	0.019	0.017	0.017	0.06 (max)
Si	(Silicon)	0.028	0.047	0.030	–
Cu	(Copper)	0.110	0.075	0.107	–
Sn	(Tin)	0.005	0.004	0.005	–
Ni	(Nickel)	0.118	0.195	0.093	–
Cr	(Chromium)	0.135	0.146	0.097	–
Mo	(Molybdenum)	0.045	0.050	0.049	–
Al	(Aluminum)	0.001	0.001	0.001	–
V	(Vanadium)	0.024	0.025	0.026	0.01 (min)*
Nb	(Niobium)	0.020	0.028	0.026	0.005 (min)*
Zr	(Zirconium)	0.002	0.002	0.002	–
Ti	(Titanium)	0.001	0.001	0.001	0.02 (min)*
B	(Boron)	0.0003	0.0003	0.0003	–
Ca	(Calcium)	0.0005	0.0006	0.0005	–
Co	(Cobalt)	0.009	0.009	0.008	–
Fe	(Iron)	Balance	Balance	Balance	Balance
Carbon Equivalent, CE_{IIW} [2]		0.42	0.47	0.43	–

1 – Product Analysis per API 5LX, 23rd Edition, 1980, for welded, non-expanded or cold-expanded Grade X60 pipe.

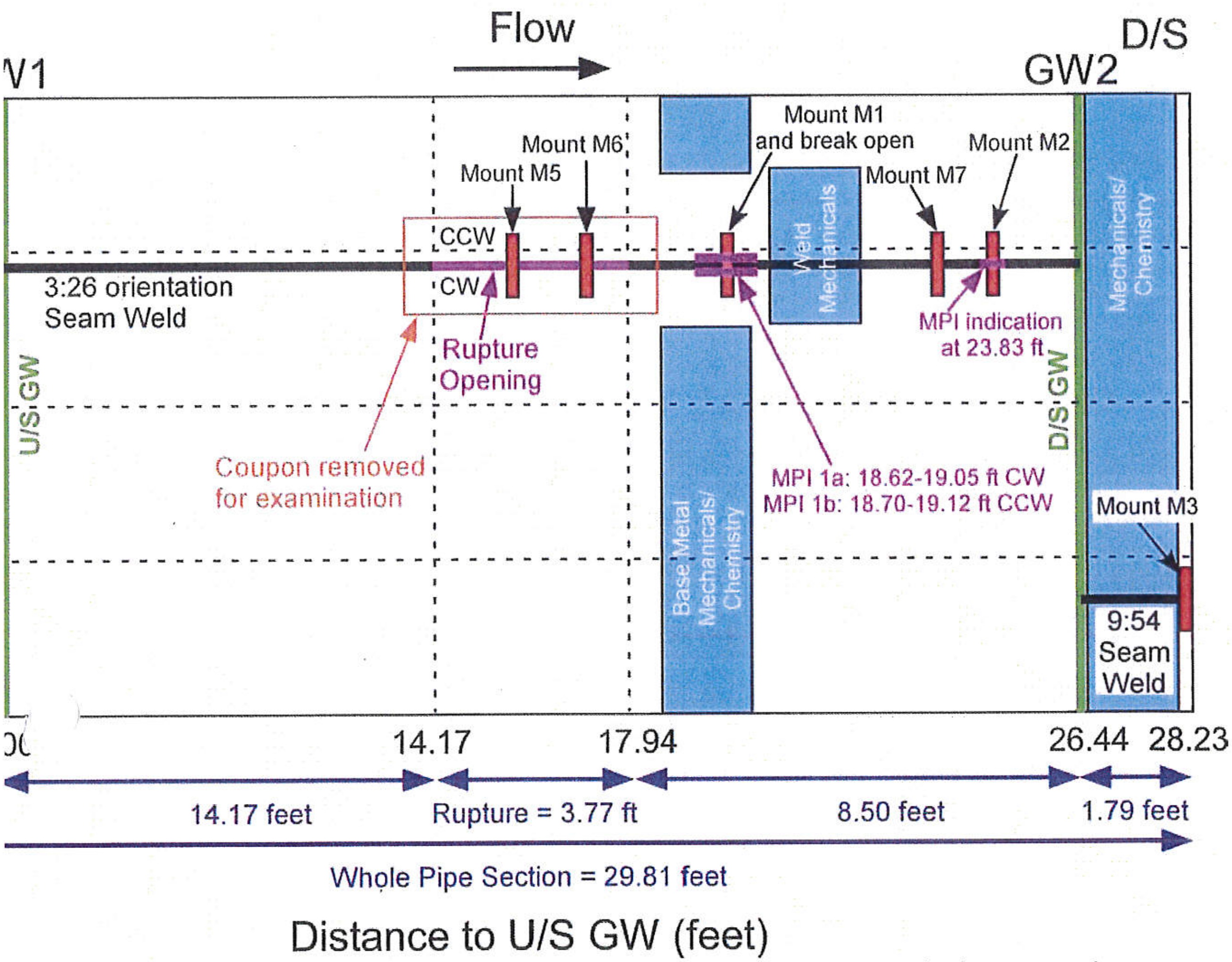
2 – $CE_{IIW} = C + (Mn/6) + (Cr+Mo+V)/5 + (Ni+Cu)/15$

* – Either niobium, vanadium, or titanium, or a combination thereof, shall be used at the discretion of the manufacturer.

Table 13. Results of failure pressure analyses using CorLAS™. The pressure at the failure site was estimated to be 665 psig.

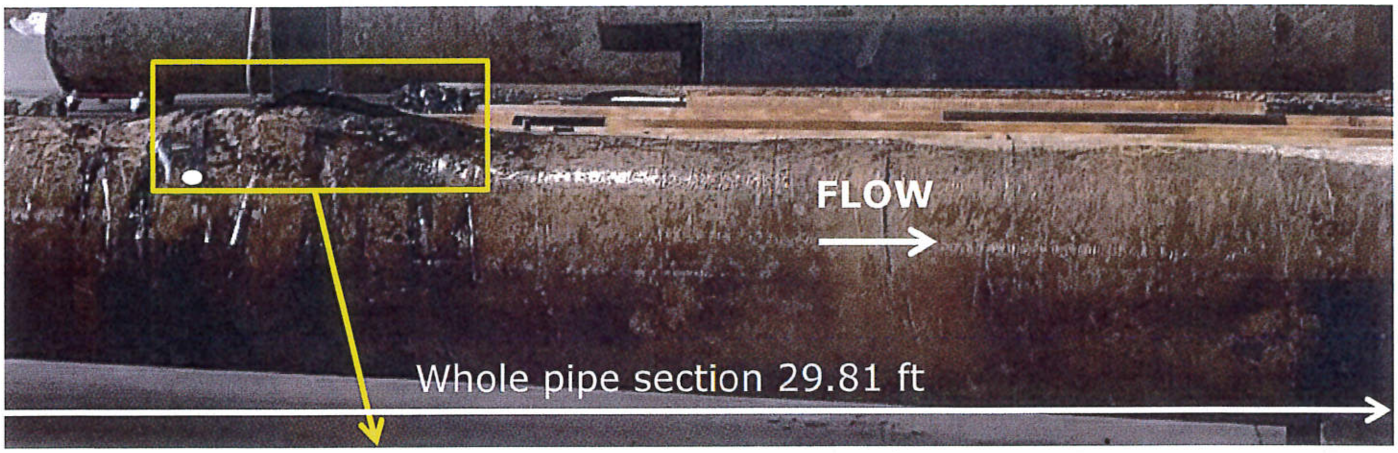
Case №	Flaw Profile	Measured Properties	Estimated Failure Pressure (psig)
1	Equivalent Flaw (Region 1)	Base Metal	1413 [1]
2	Equivalent Flaw (Region 1+Region 2)	Base Metal	658 [1]
3	Equivalent Flaw (Region 1)	HAZ	1394 [1]
4	Equivalent Flaw (Region 1+ Region 2)	HAZ	664 [1]

1- J Fracture Toughness failure criterion

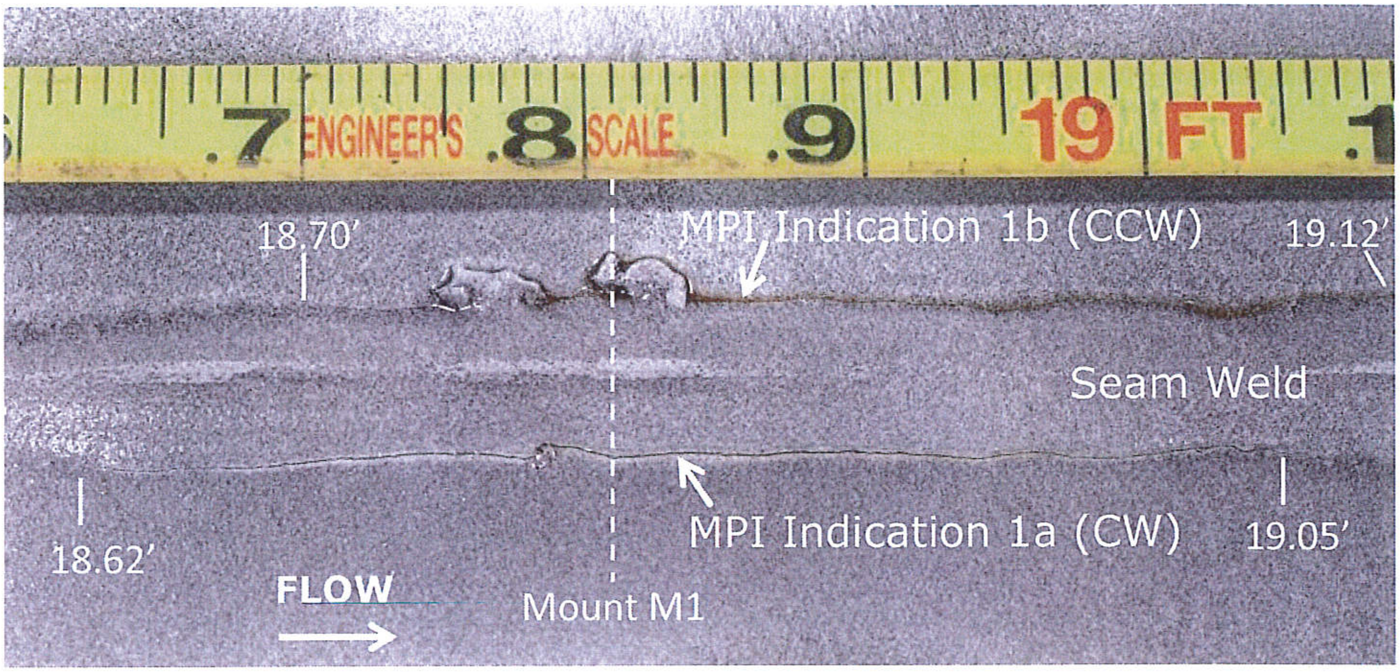


: of Pipe Section showing the location of the rupture, MPI indications, and where samples were removed nical testing, chemistry, and metallography (Mounts M1, M2, M3, M4, M5, M6, M7).

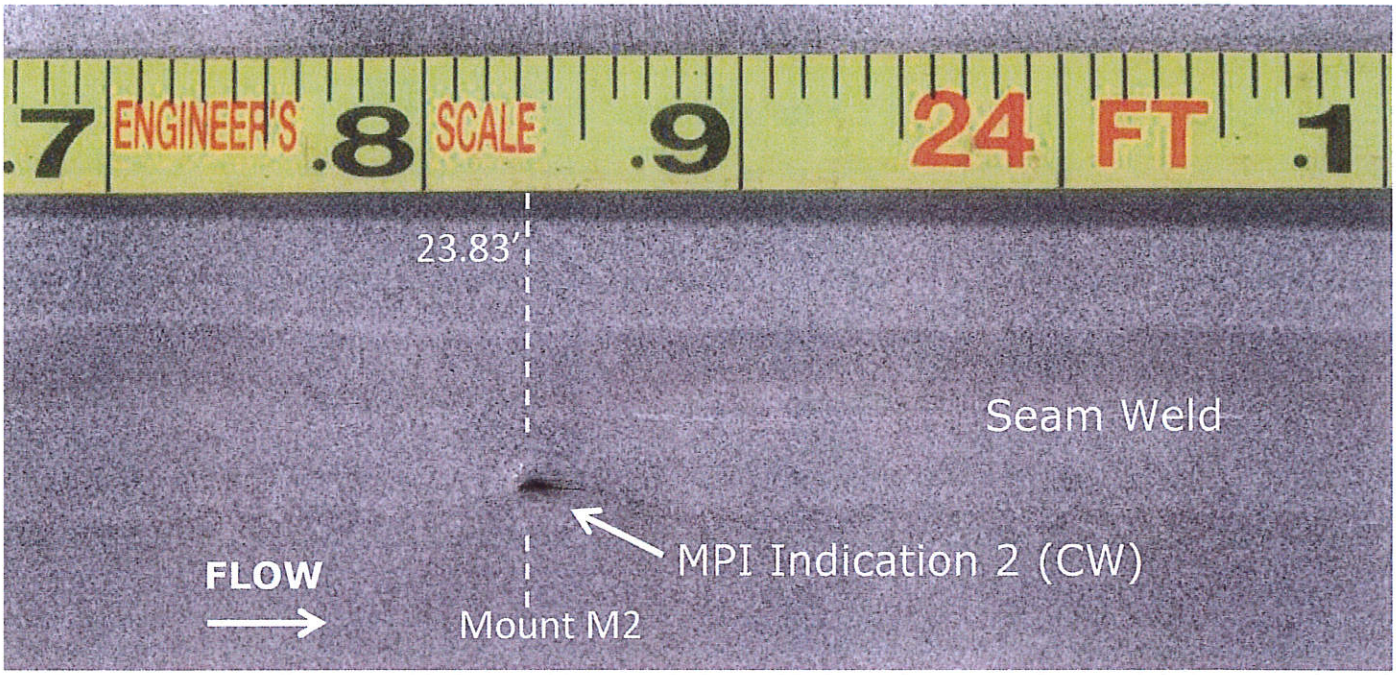
gure 2. Photograph of Pipe Section in the as-received condition at DNV GL.



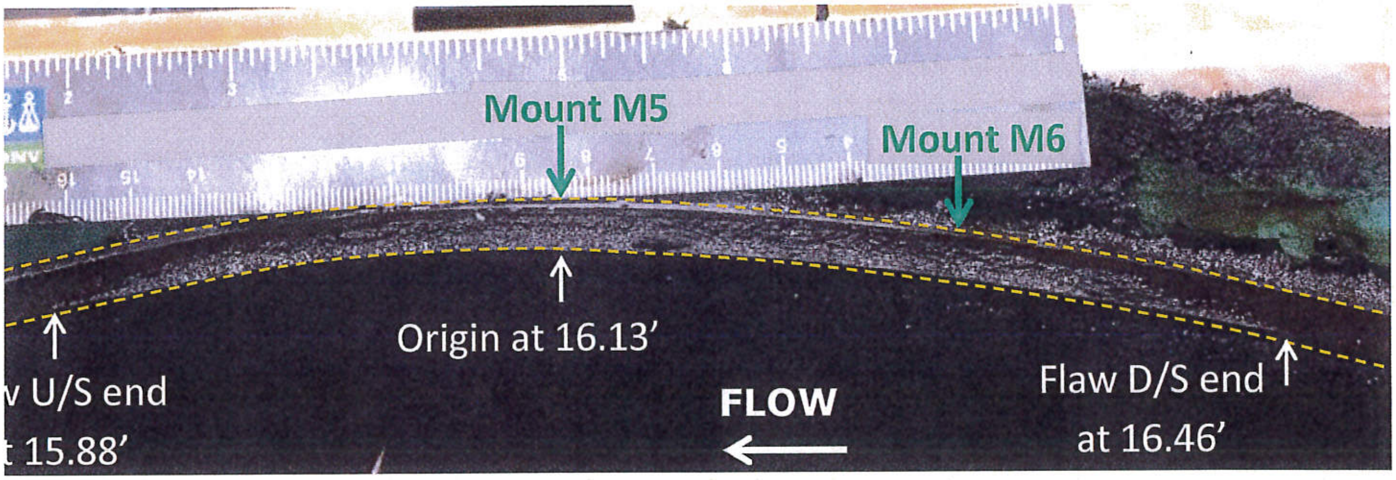
ıhs of Pipe Section showing the rupture location following removal of the protective plastic wrappings.



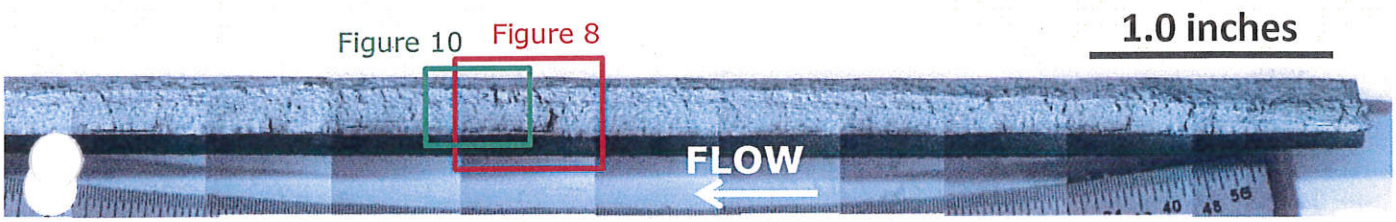
ph the internal pipe surface showing MPI Indication 1a and MPI Indication 1b along the clockwise (nterclockwise (CCW) side of the seam weld, approximately 2.7 feet downstream of the rupture 18.62 - 19.12 ft D/S from U/S GW), and location where Mount M1 was removed.



h he internal pipe surface showing MPI Indication 2 along the clockwise (CW) side of the seam weld, ate., 7.7 feet downstream of the rupture location (23.83 ft D/S from U/S GW), and location where was removed.



ɪh of the fracture surface (clockwise side) at the suspected rupture origin before cleaning. Light gray e-existing flaw that initiated from the pipe inside surface.



age of the fracture surface (clockwise side) at the suspected rupture origin after cleaning in a degreaser anol. Light gray area is the pre-existing flaw that initiated from the pipe inside surface.

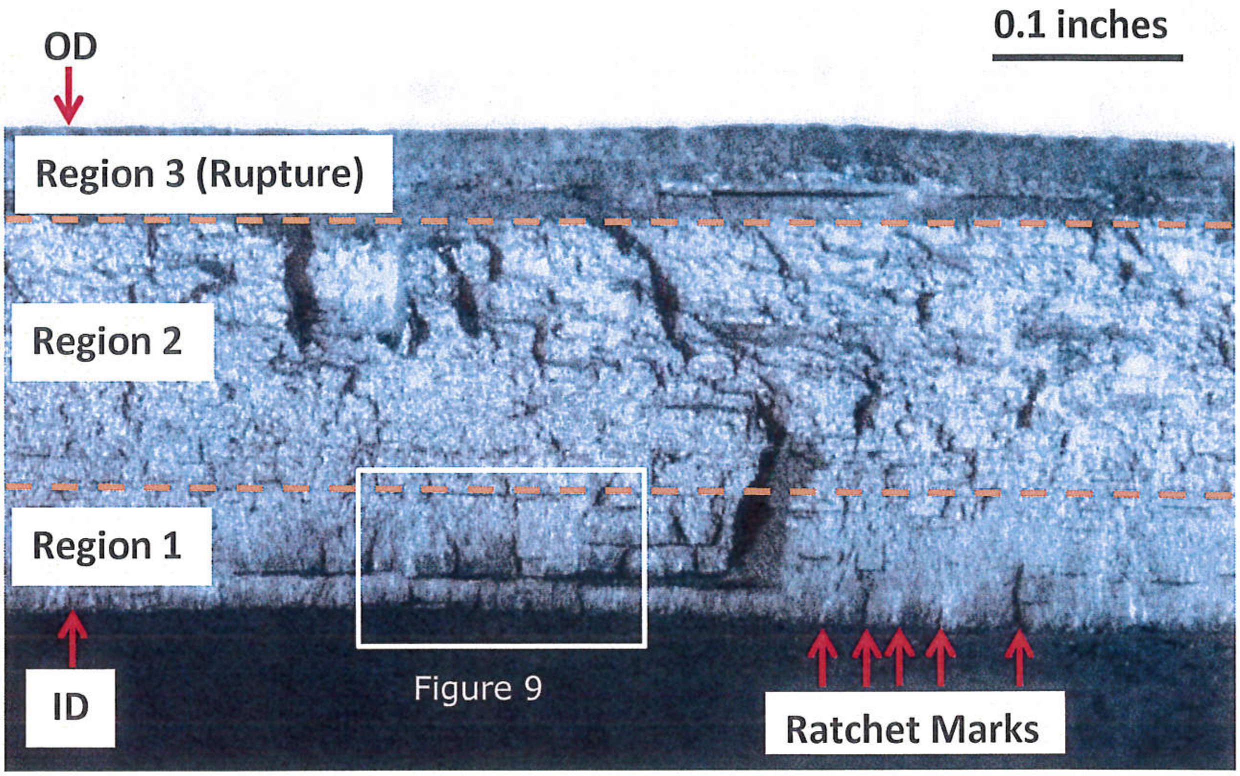


Figure 8. Photomicrograph showing a portion of the fracture surface from the rupture, clockwise (CW) side of the seam weld, after cleaning with a degreaser and methanol. Area indicated in Figure 7.

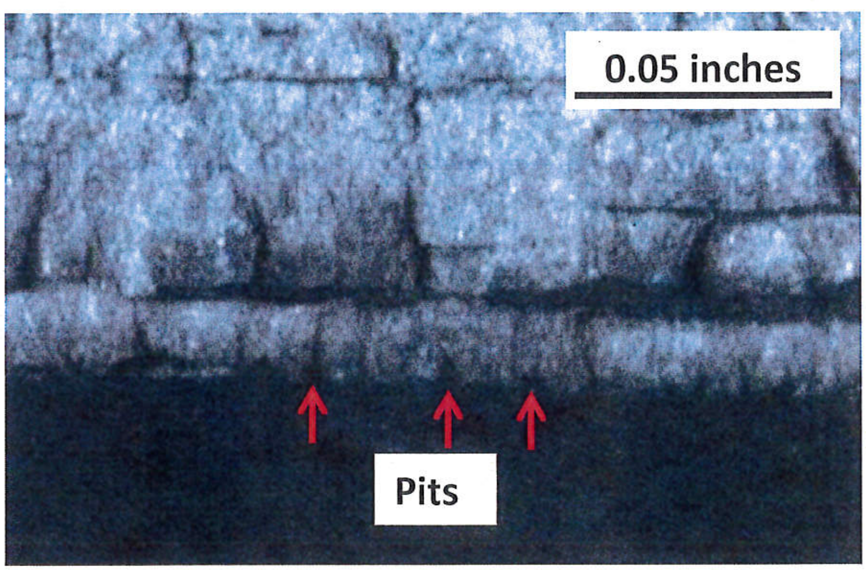


Figure 9. Photomicrograph showing close-up view of pits at ID pipe surface; area indicated in Figure 8.

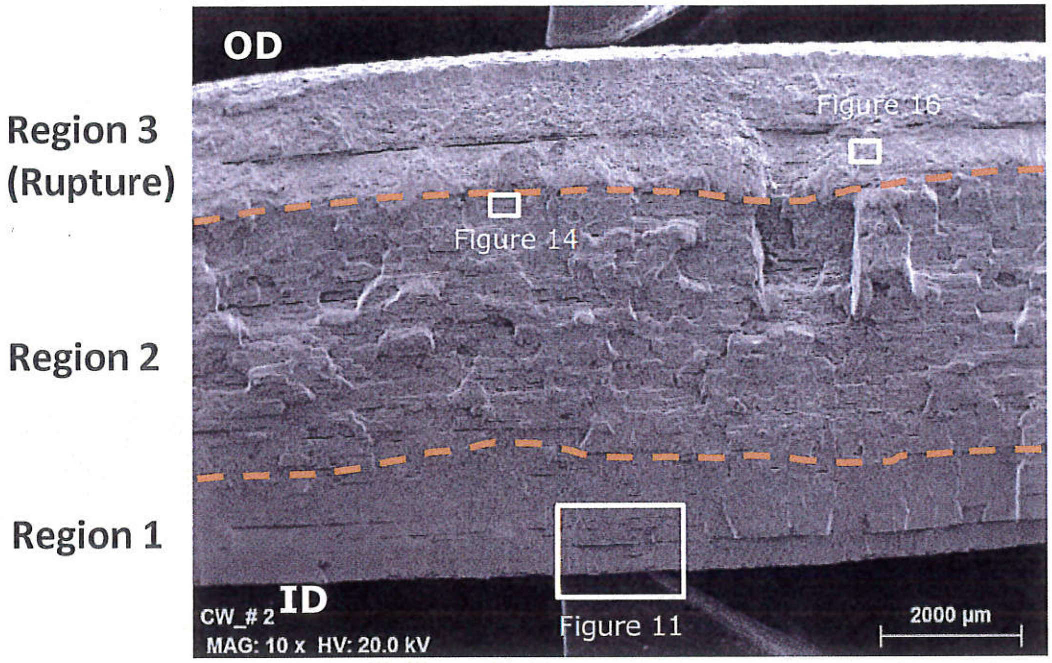


Figure 10. SEM photomicrograph showing three distinct morphologies on fracture surface from rupture, 10X; area indicated in Figure 7

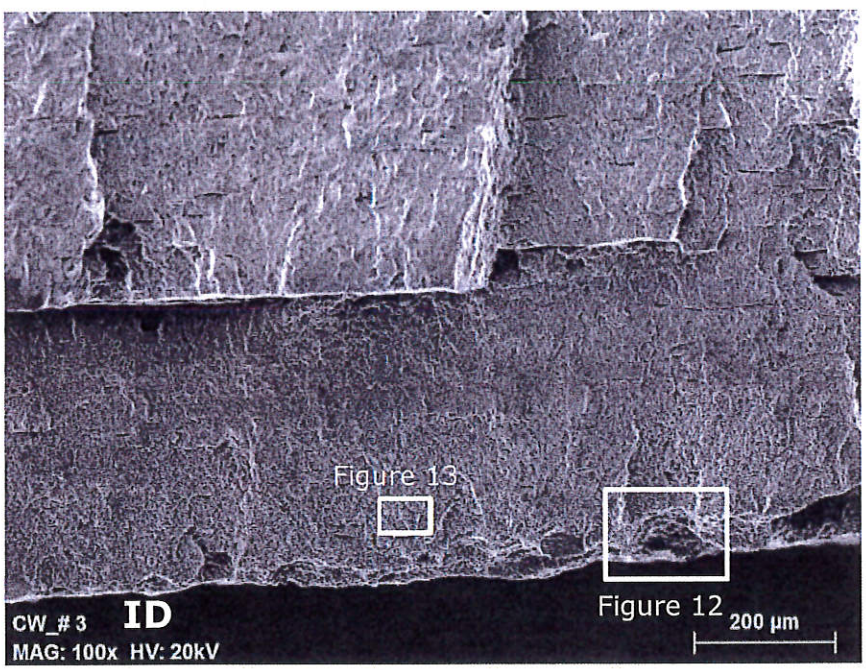


Figure 11. SEM photomicrograph showing Region 1 of fracture surface from rupture, 100X; area indicated in Figure 10.

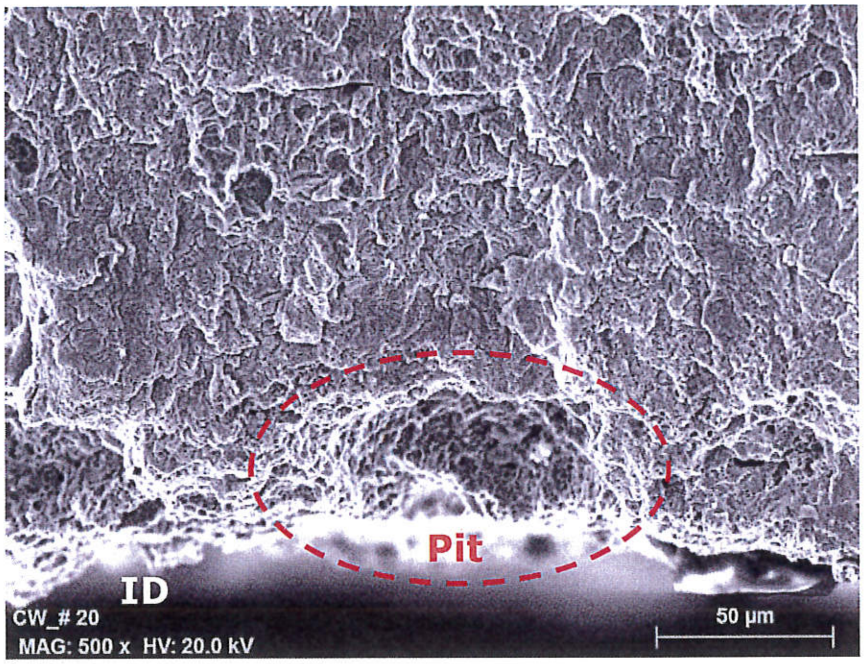


Figure 12. SEM photomicrograph showing pit at ID surface 500X; area indicated in Figure 11.

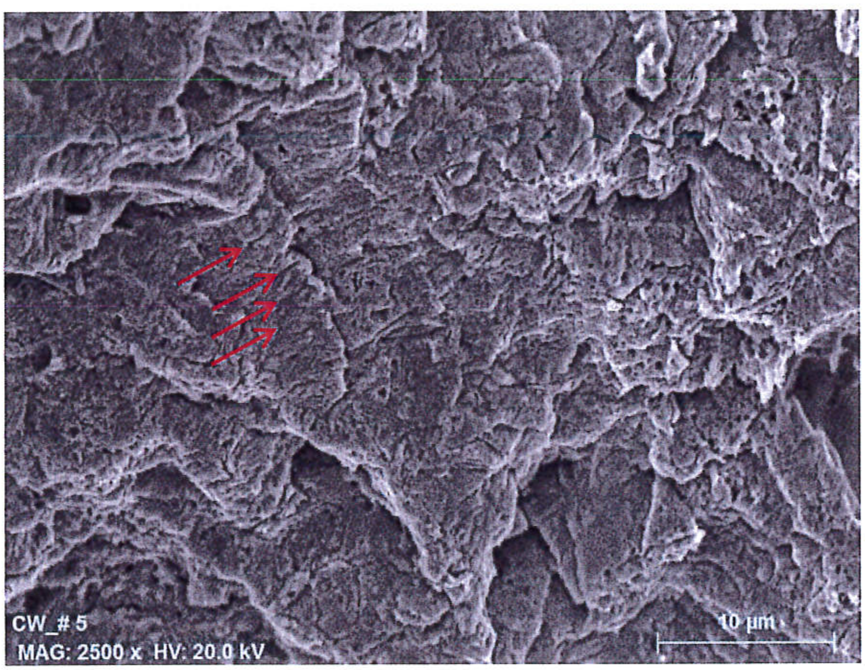


Figure 13. SEM photomicrograph showing fatigue striations in Region 1, 2500X; area indicated in Figure 11.

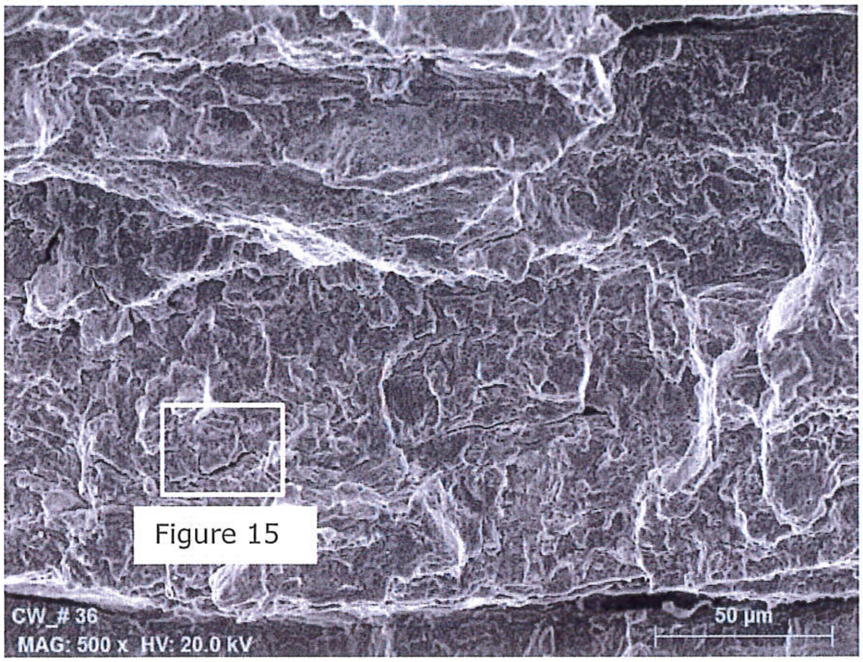


Figure 14. SEM photomicrograph showing secondary cracking within Region 2, 500X; area indicated in Figure 10.

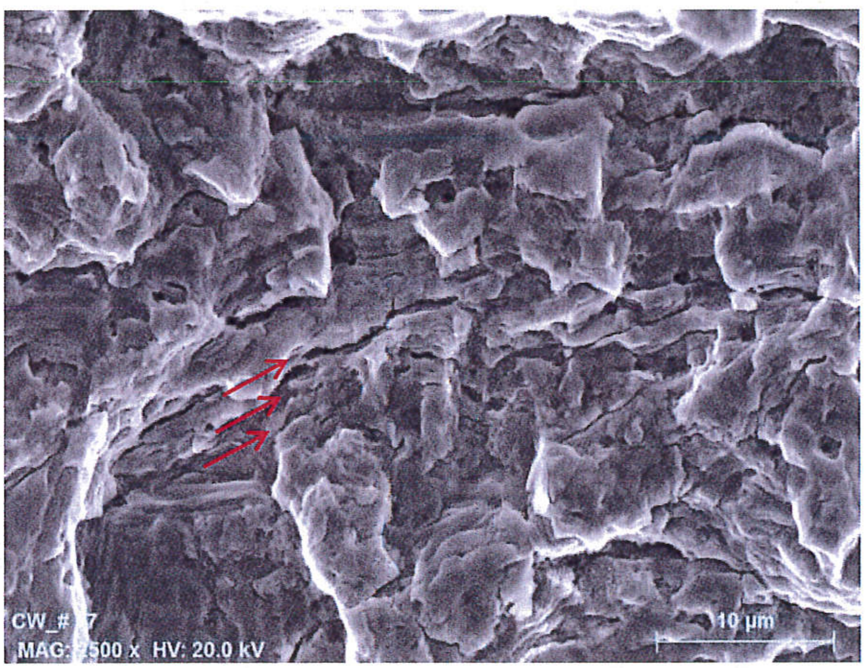


Figure 15. SEM photomicrograph showing small cracks on corrosion product-covered fracture surface in Region 2, 2500X; area indicated in Figure 14.

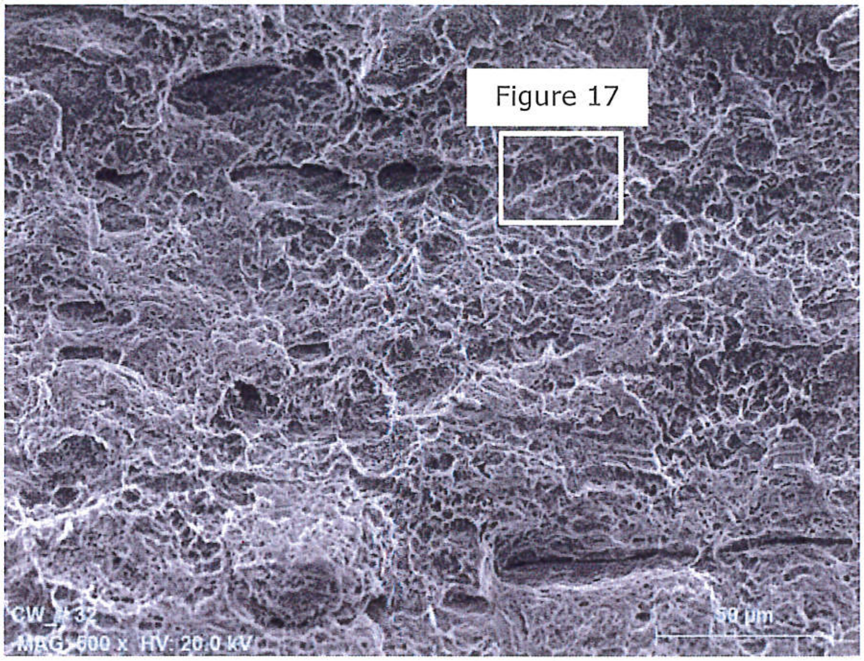


Figure 16. SEM photomicrograph showing ductile fracture morphology in Region 3, 500X; area indicated in Figure 10.

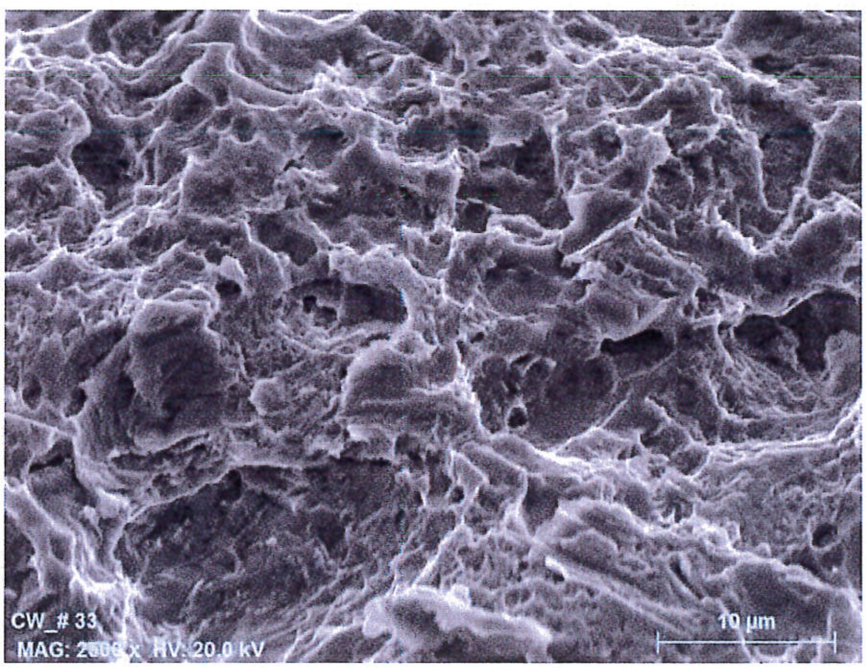
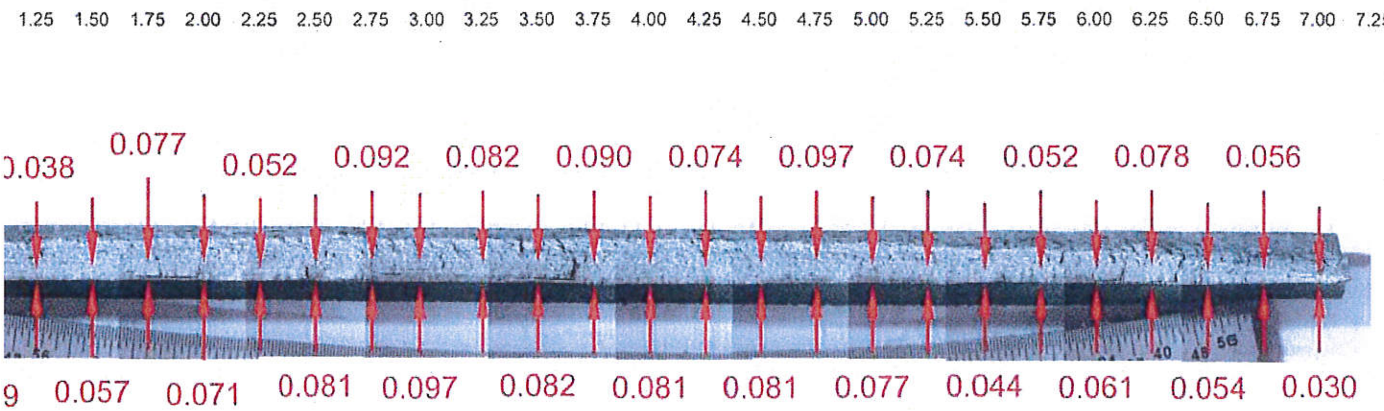
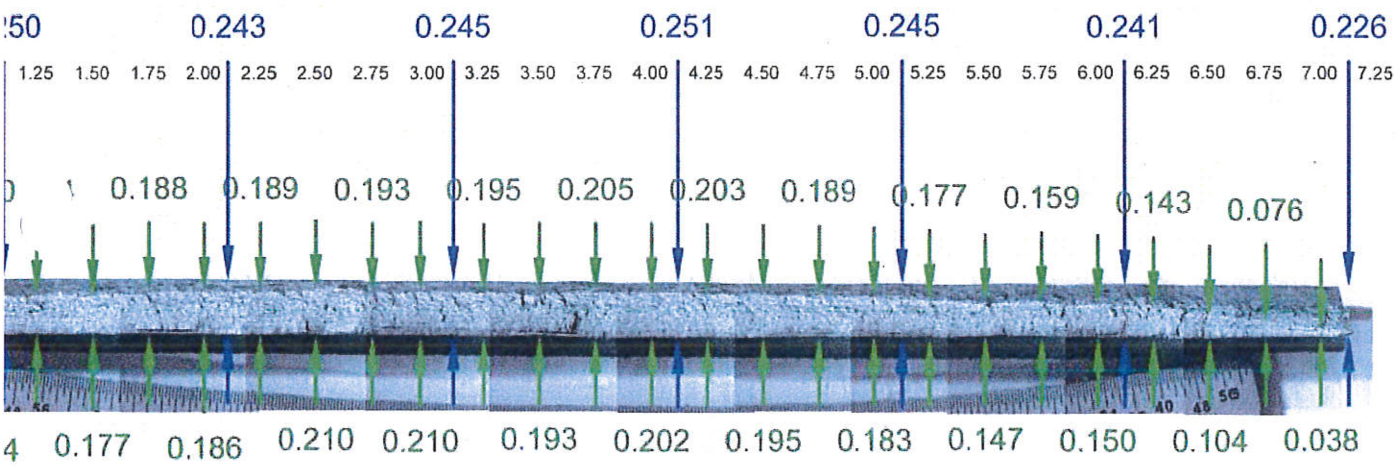


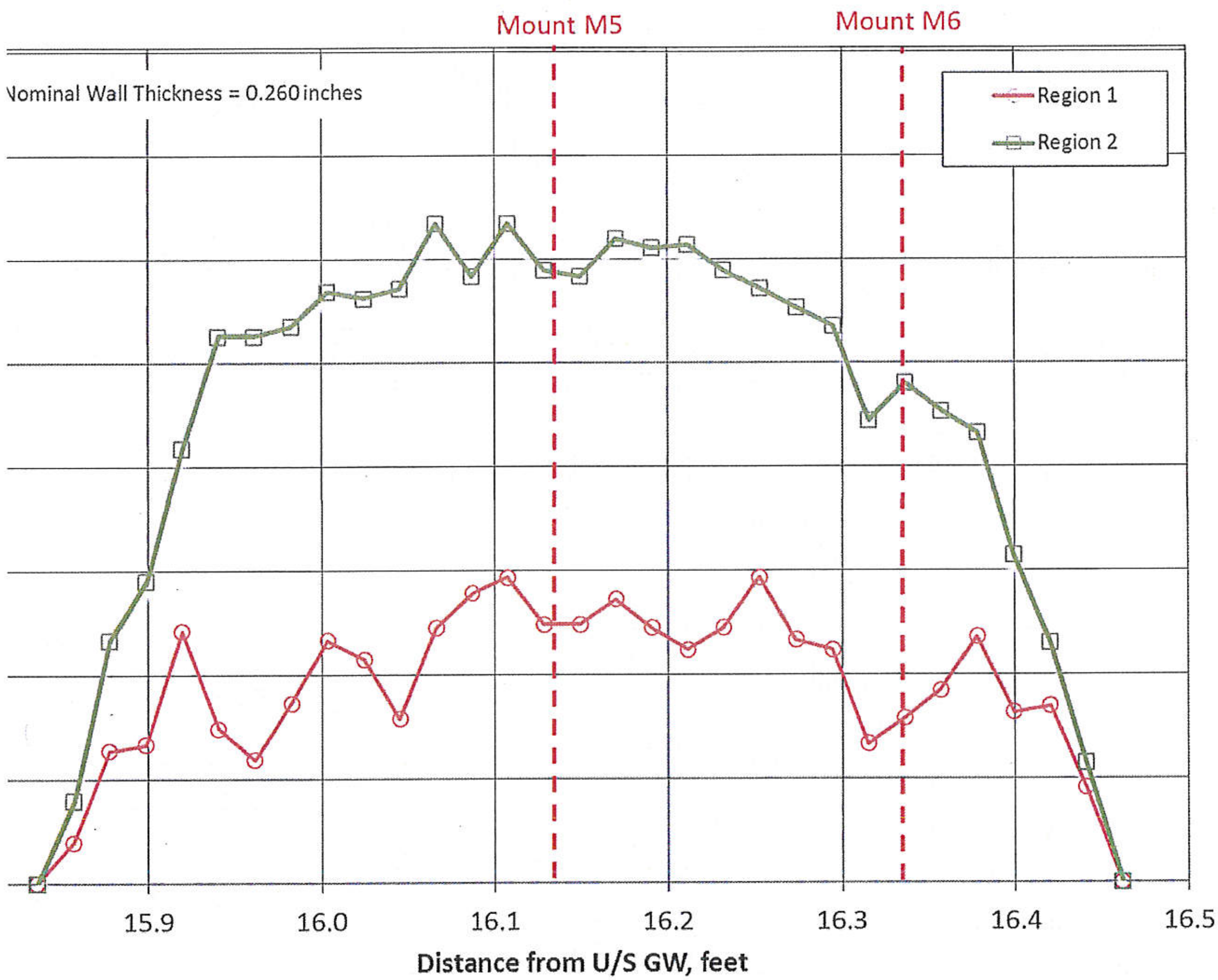
Figure 17. SEM photomicrograph showing ductile fracture morphology in Region 3, 2500X; area indicated in Figure 16.



age of the fracture surface (clockwise side), showing depth measurements (red) of Region 1 of the pre-
aw.



age of the fracture surface (clockwise side), showing depth measurements (green) of Region 1 and
of the pre-existing flaw, together with wall thickness measurements (blue).



h versus distance from the U/S GW for Region 1 and Region 2 identified on the fracture surface. The of Mount M5 and Mount M6 are indicated by dashed lines.

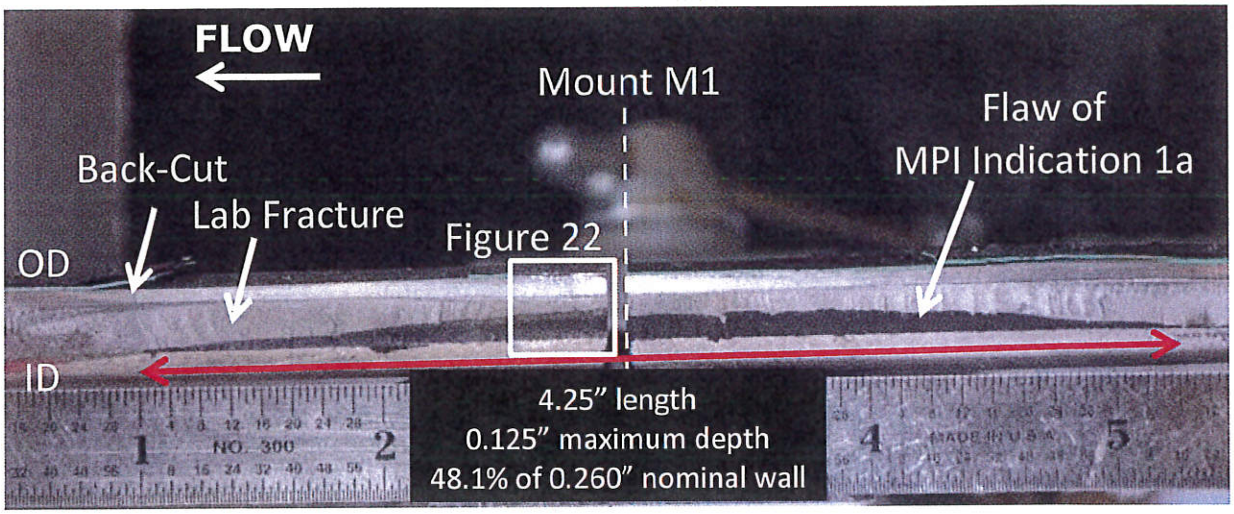


Figure 21. Photograph of the clockwise (CW) side of the fracture surface associated with MPI Indication 1a, and location of Mount M1.

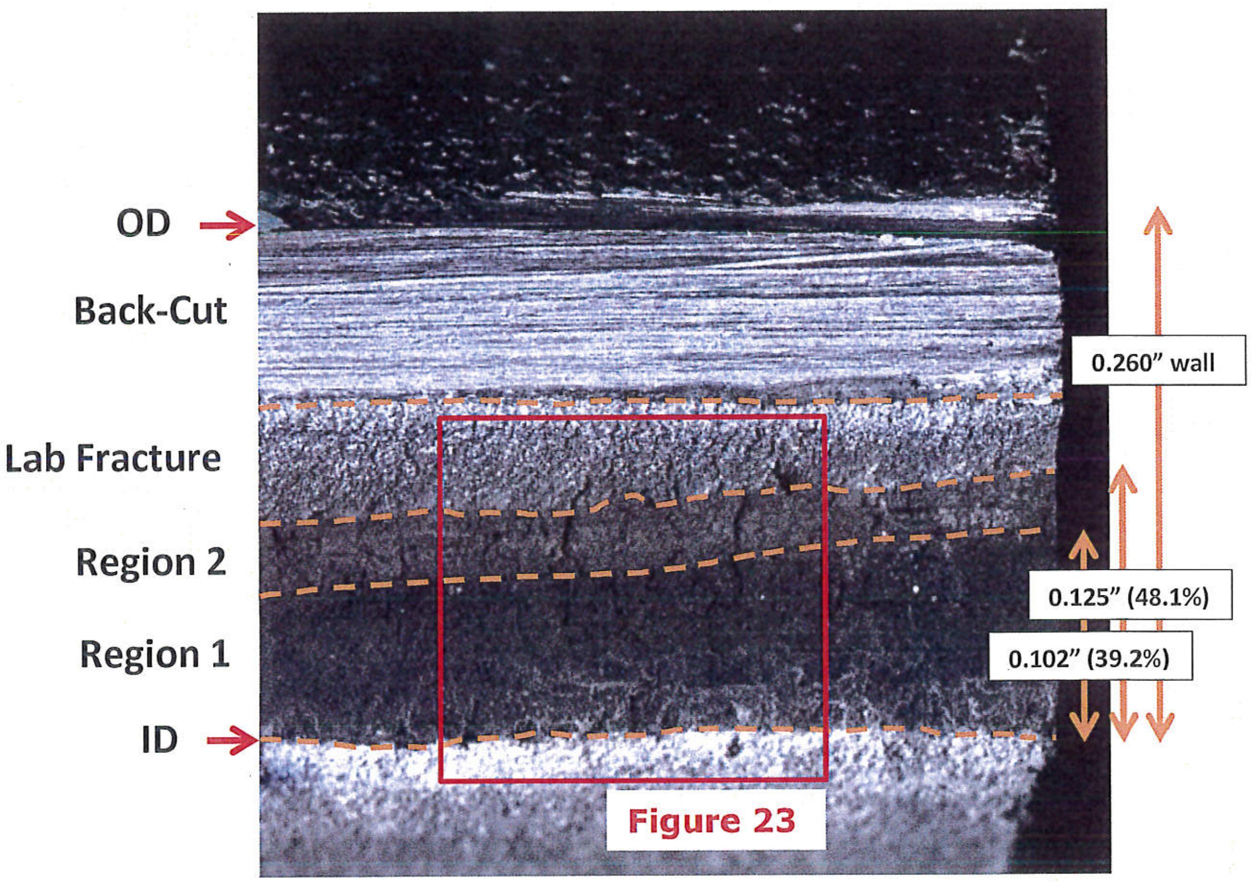


Figure 22. Stereo-photograph showing a portion of the fracture surface associated with broken open MPI Indication 1a, without cleaning. Area indicated in Figure 21.

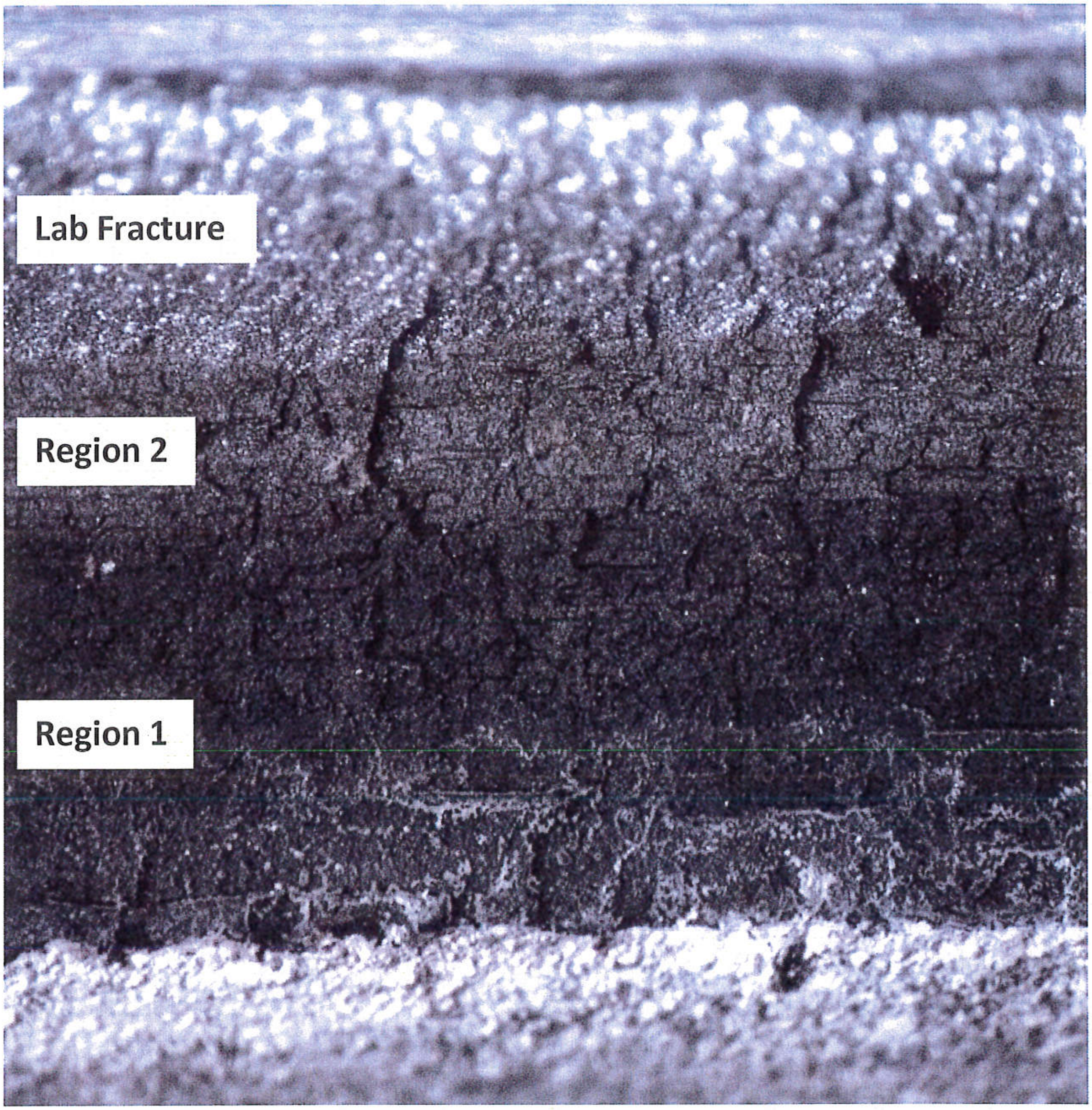


Figure 23. Stereo-photograph showing a close-up view of the fracture surface associated with broken open MPI Indication 1a, without cleaning. Area indicated in Figure 22.

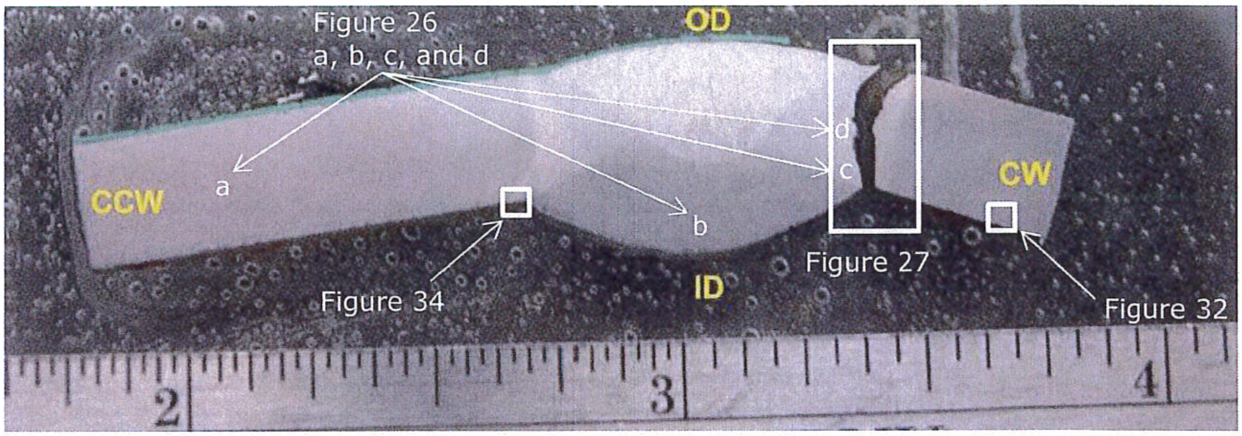


Figure 24. Photograph of the mounted cross-section (Mount M5) removed from the likely rupture origin; 16.13 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

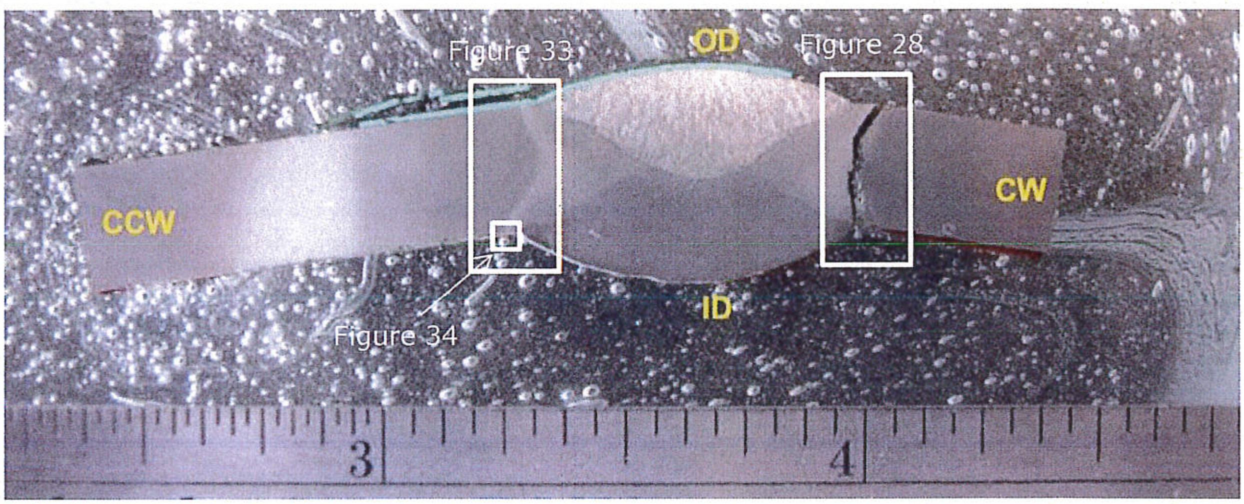
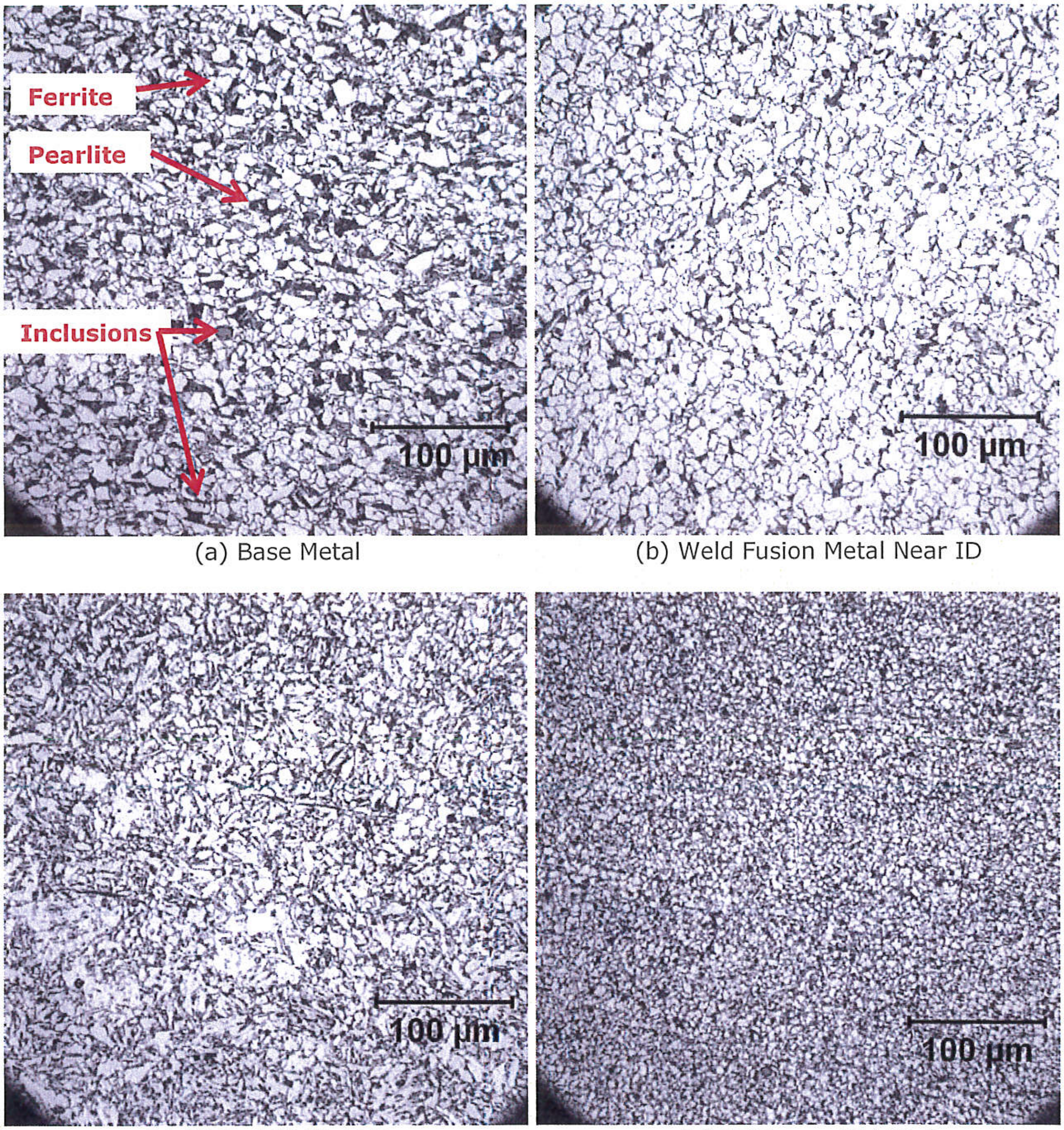


Figure 25. Photograph of the mounted cross-section (Mount M6) removed from the ruptured joint, just D/S from the likely rupture origin; 16.33 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.



(a) Base Metal

(b) Weld Fusion Metal Near ID

(c) HAZ at ID Weld Toe

(d) HAZ near Mid-Wall

Figure 26. Photomicrographs of Mount M5, showing microstructure of (a) base metal, (b) weld fusion metal near ID, (c) HAZ metal near ID weld toe, and (d) HAZ metal near mid-wall. Locations indicated in Figure 25. 4% Nital Etch.

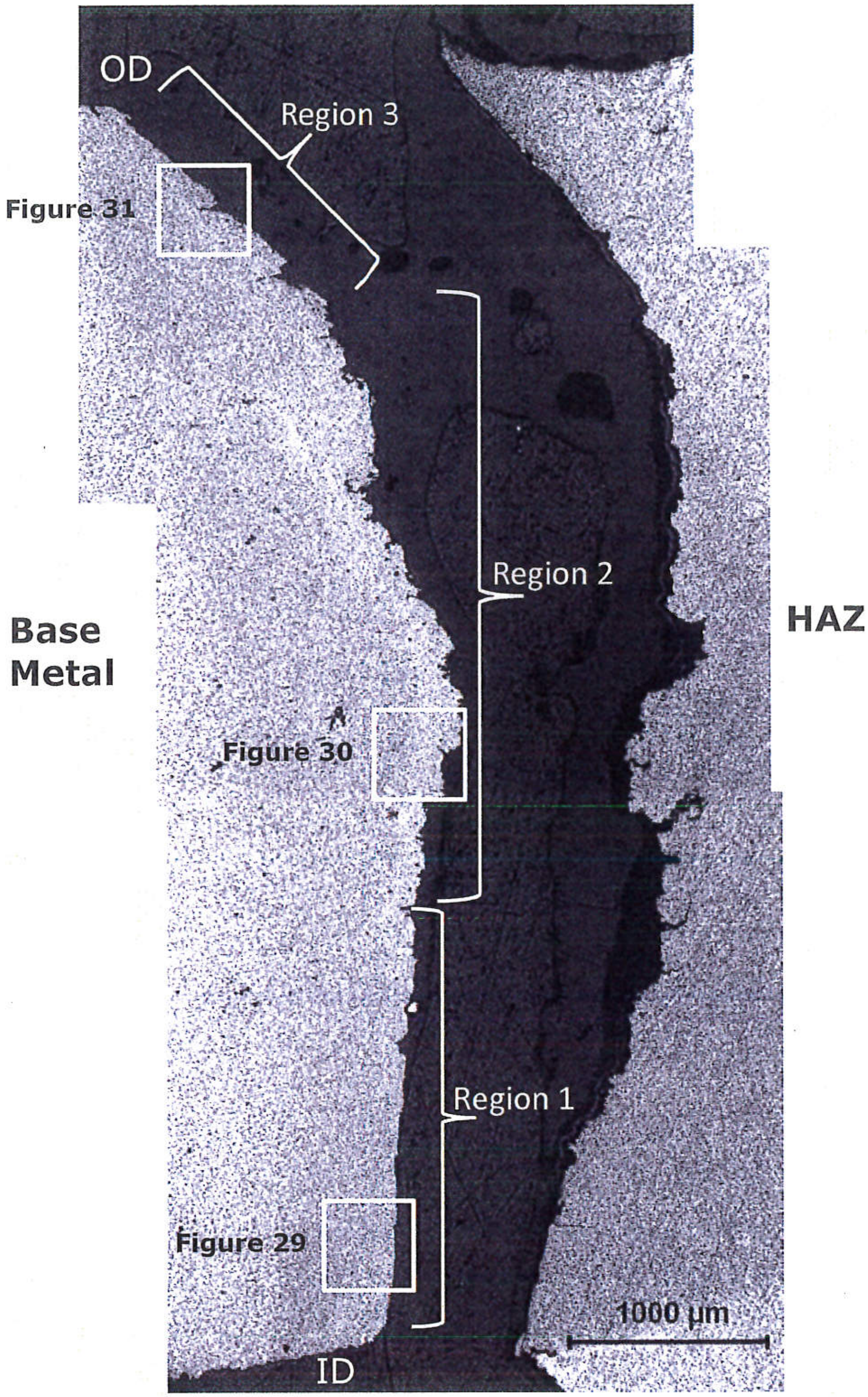


Figure 27. Photomicrograph of Mount M5, clockwise (CW) side of the weld, showing the fracture path in cross-section; area indicated in Figure 24. 4% Nital Etch.

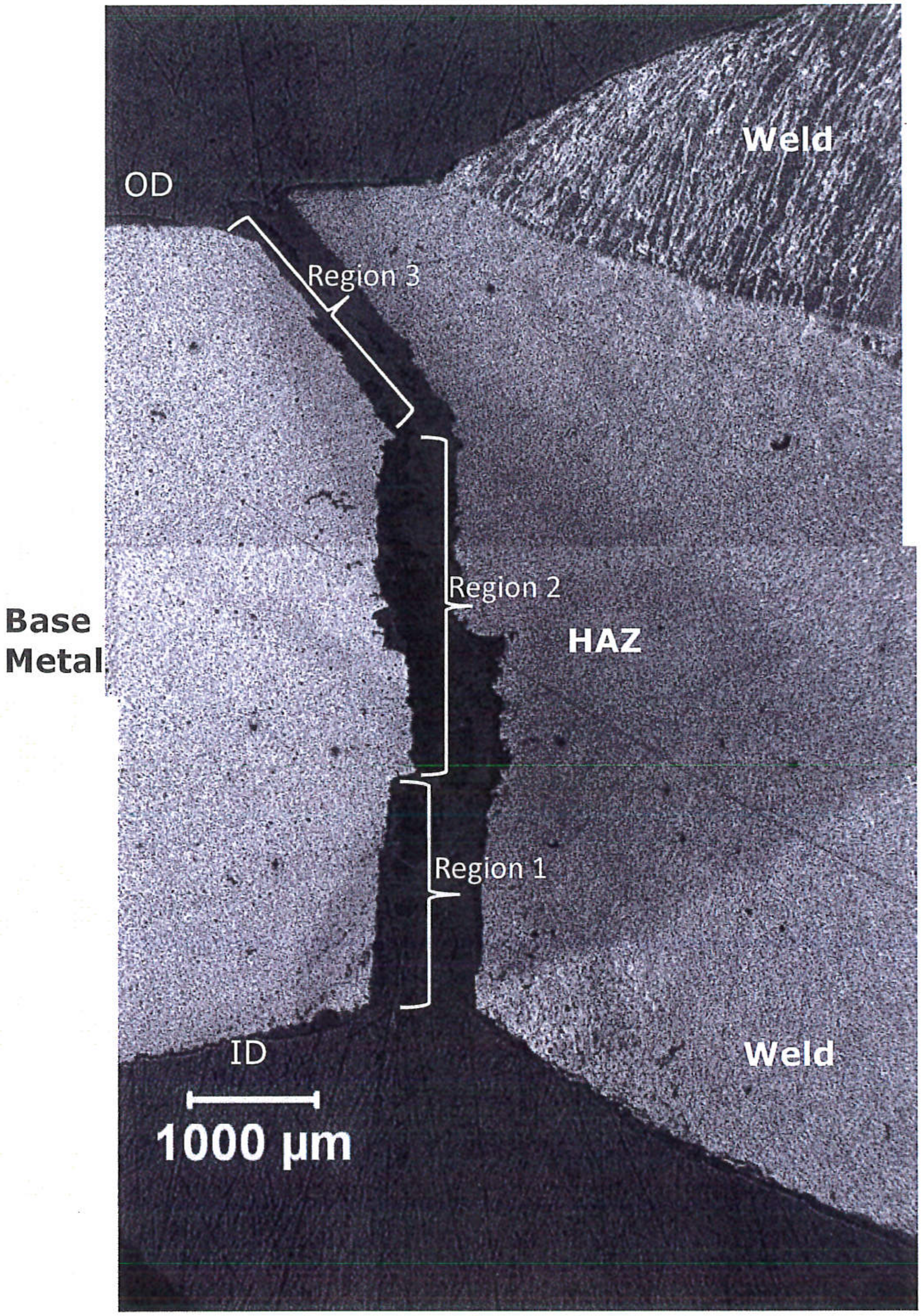


Figure 28. Photomicrograph of Mount M6, clockwise (CW) side of the weld, showing the fracture path in cross-section; area indicated in Figure 25. 4% Nital Etch.

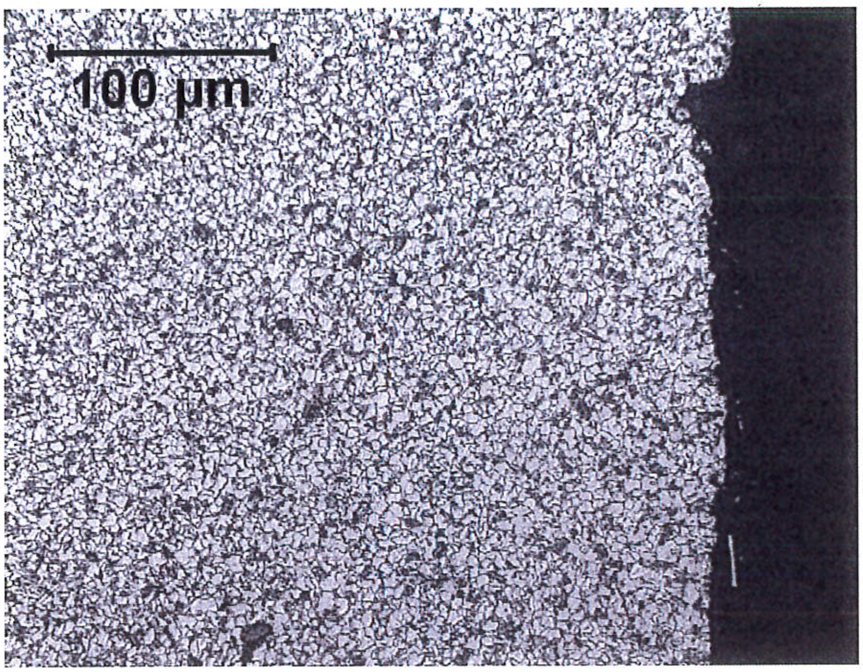


Figure 29. Photomicrograph of Mount M5 showing the microstructure and the fracture profile within Region 1 near the internal pipe surface; area indicated in Figure 27. 4% Nital Etch.

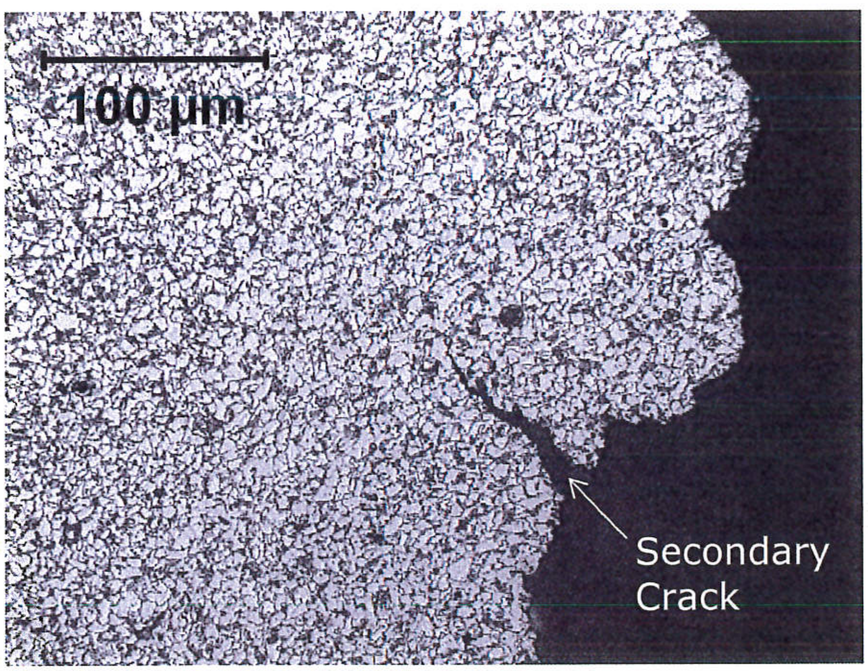


Figure 30. Photomicrograph of Mount M5 showing the microstructure and the fracture profile within Region 2; area indicated in Figure 27. 4% Nital Etch.

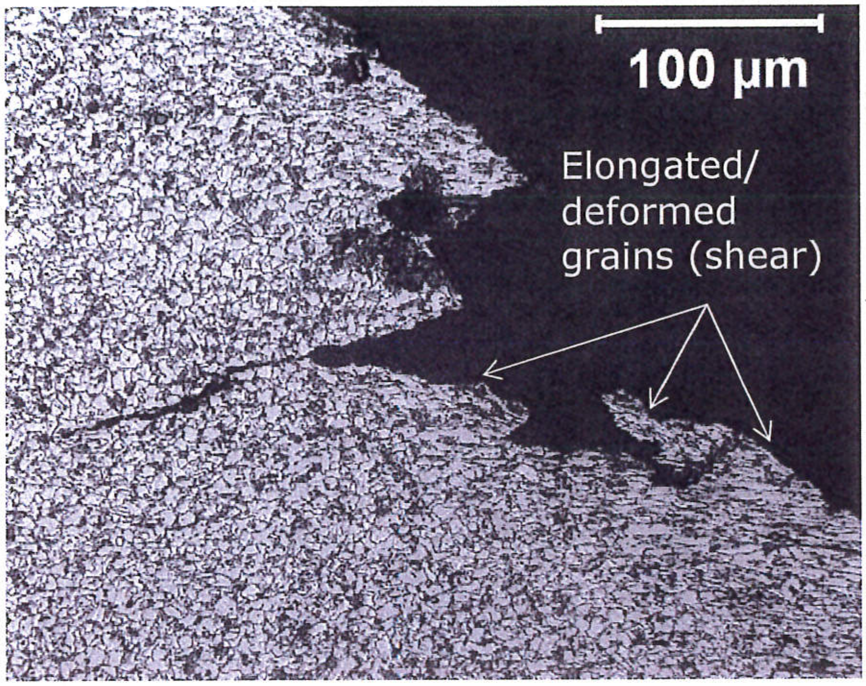
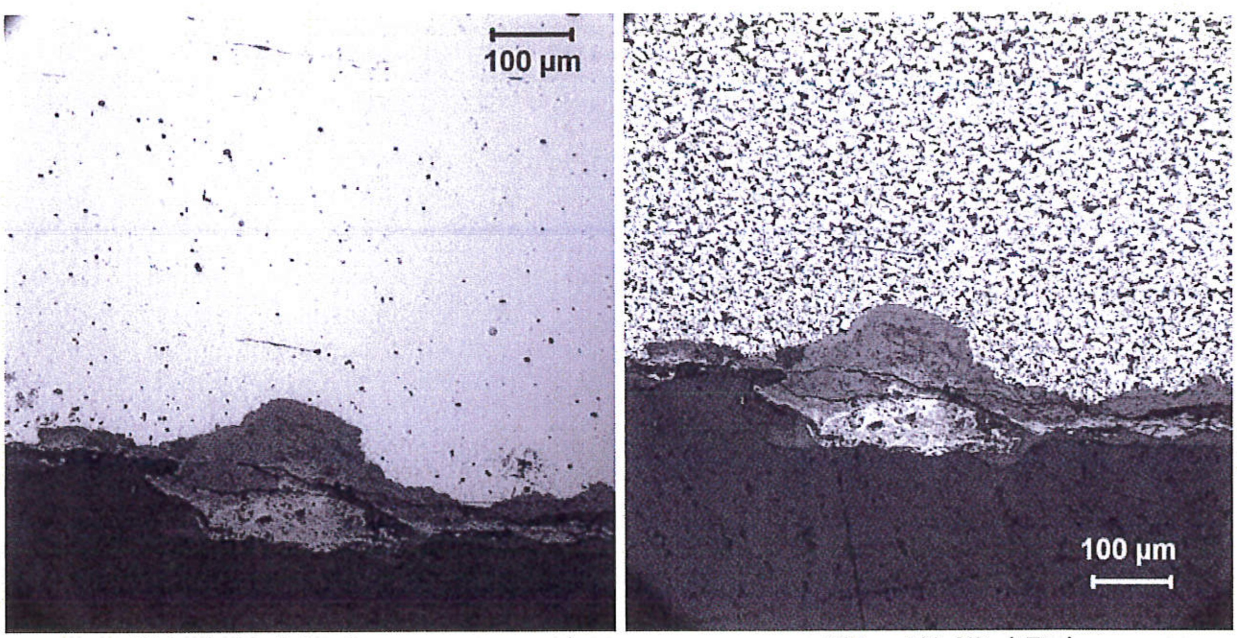


Figure 31. Photomicrograph of Mount M5 showing the microstructure and the fracture profile within Region 3 near the external pipe surface; area indicated Figure 27. 4% Nital Etch.



M5 - As Polished

M5 – 4% Nital Etch

Figure 32. Photomicrographs of Mount M5 showing round and elongated inclusions in the base metal and corrosion product in a micro-pit on the ID surface of the pipe; area indicated in Figure 24.

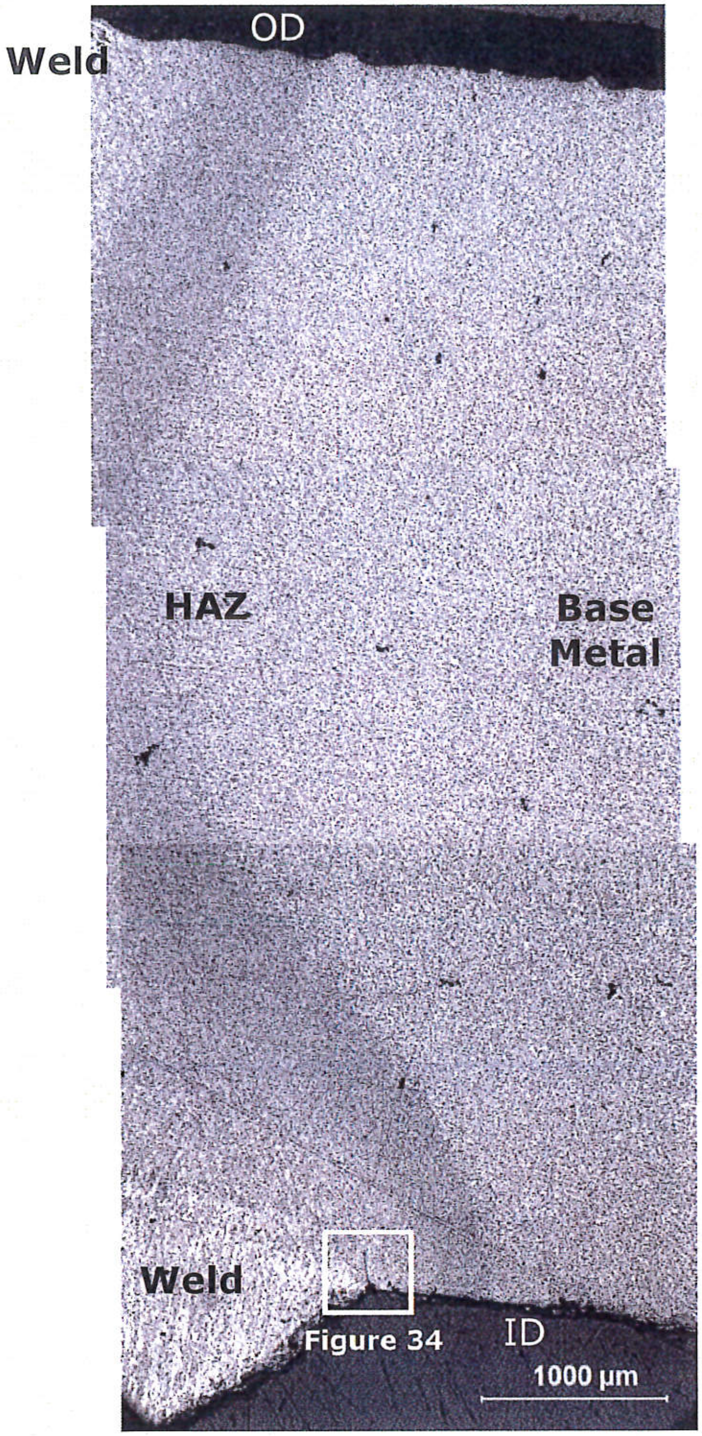
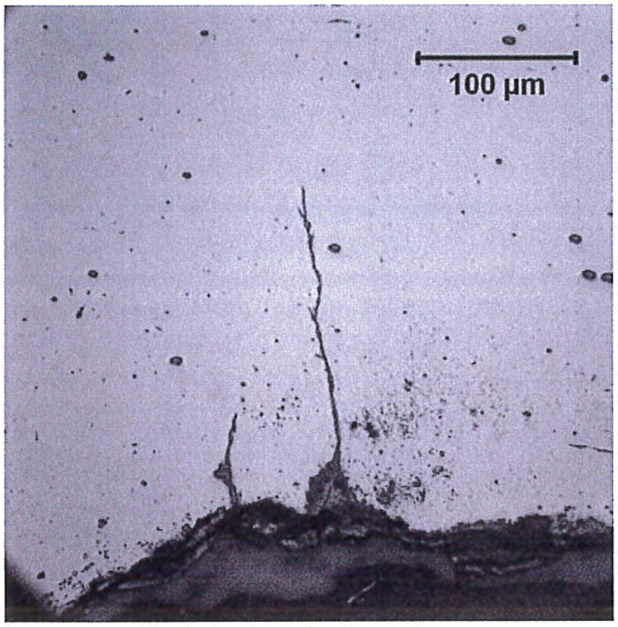
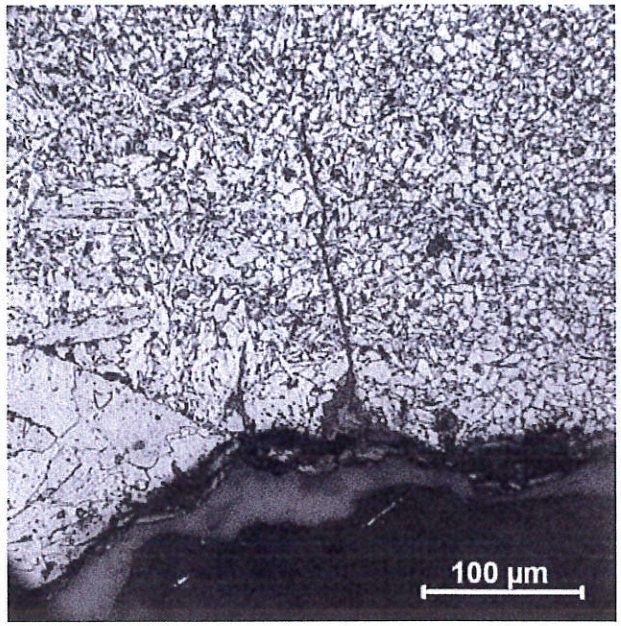


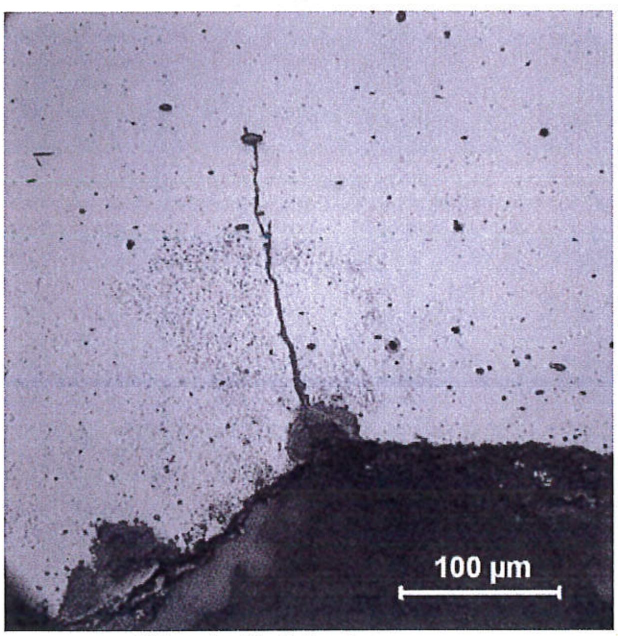
Figure 33. Photomicrograph of Mount M6, counterclockwise (CCW) side of the weld, showing a small crack at the weld toe; area indicated in Figure 25. 4% Nital Etch.



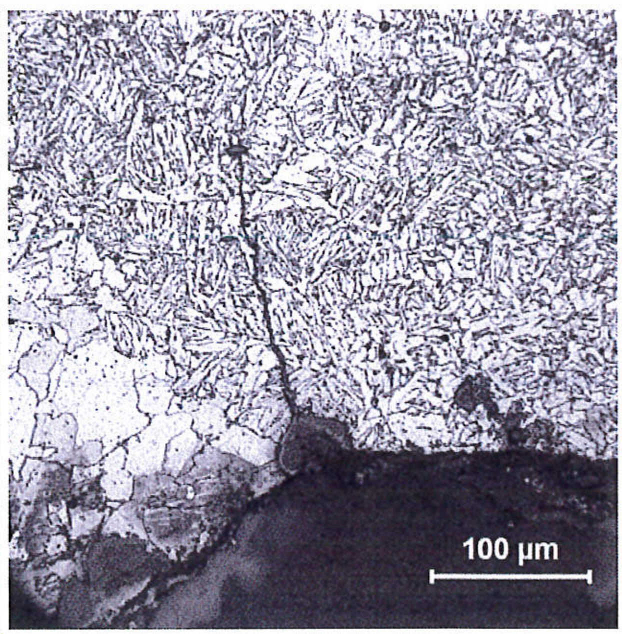
M5 - As Polished



M5 – 4% Nital Etch



M6 - As Polished



M6 – 4% Nital Etch

Figure 34. Photomicrographs of Mount M5 (top, refer to Figure 24) and Mount M6 (bottom, refer to Figure 25, showing cracks at weld toe with pits and corrosion products on ID pipe surface; counterclockwise (CCW) side of the seam weld.

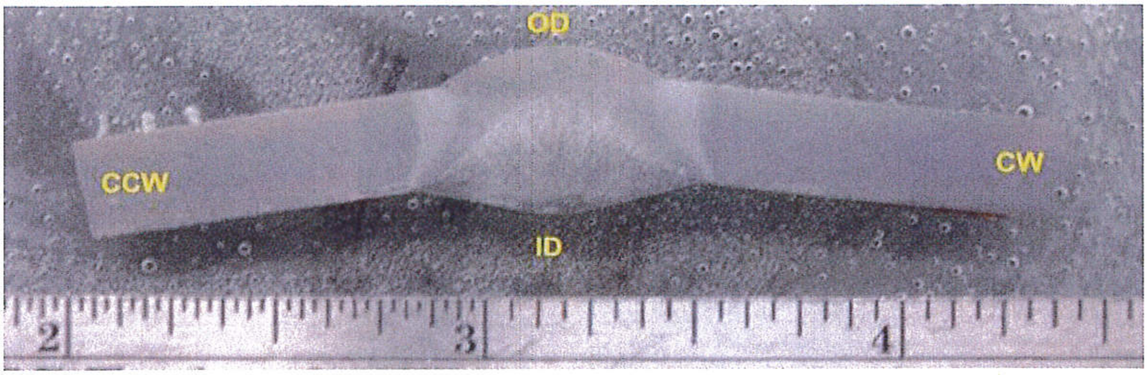


Figure 35. Photograph of the mounted cross-section (Mount M7) removed from the ruptured joint, away from the failure; 21.16 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

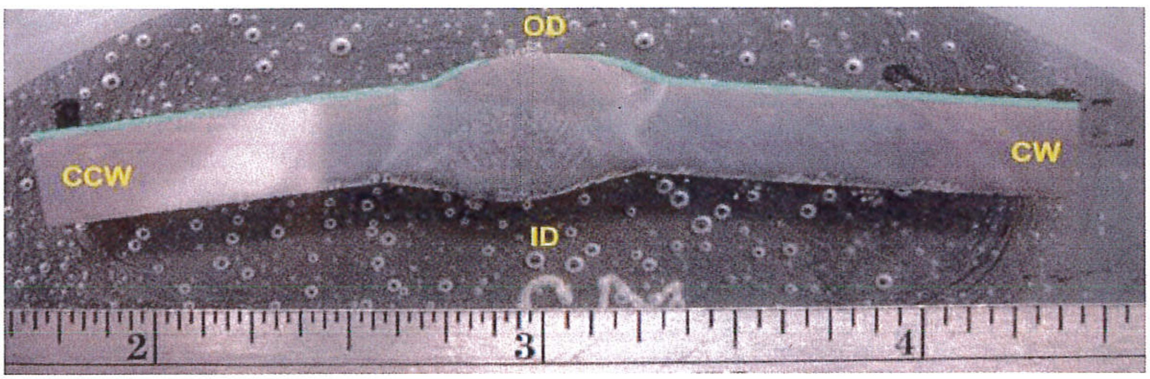


Figure 36. Photograph of the mounted cross-section (Mount M3) removed from D/S joint; 28.19 feet from the U/S GW (of the ruptured joint). Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

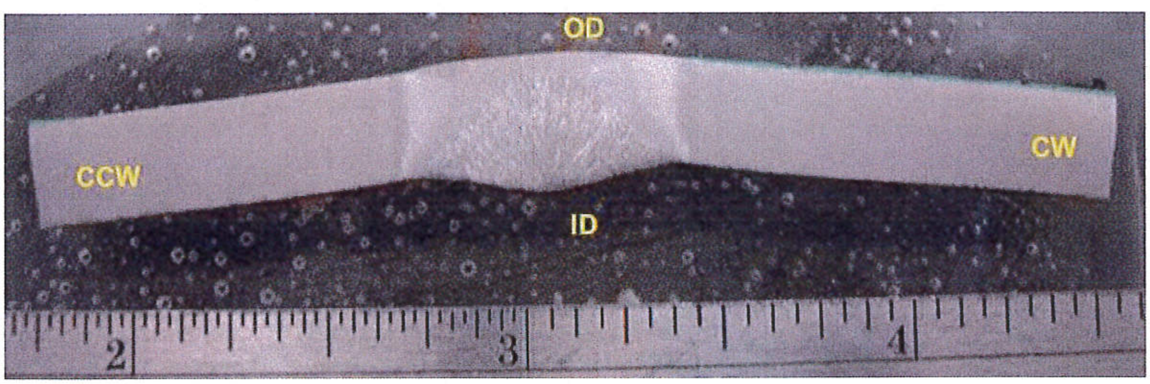


Figure 37. Photograph of the mounted cross-section (Mount M4) removed from U/S joint; -1.54 feet from the U/S GW (of the ruptured joint). Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

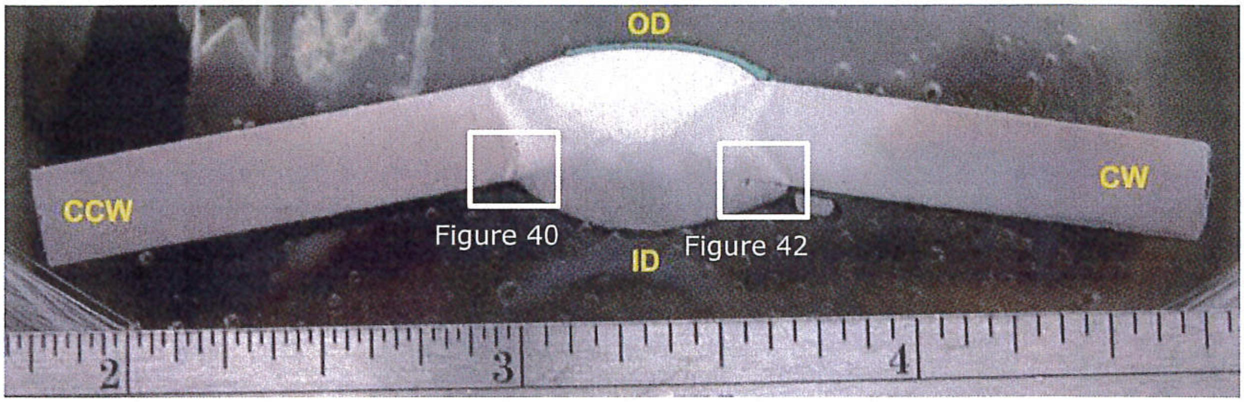


Figure 38. Photograph of the mounted cross-section (Mount M1) removed from MPI Indication 1a (CW) and MPI Indication 1b (CCW) of the ruptured joint, away from the rupture; 18.81 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

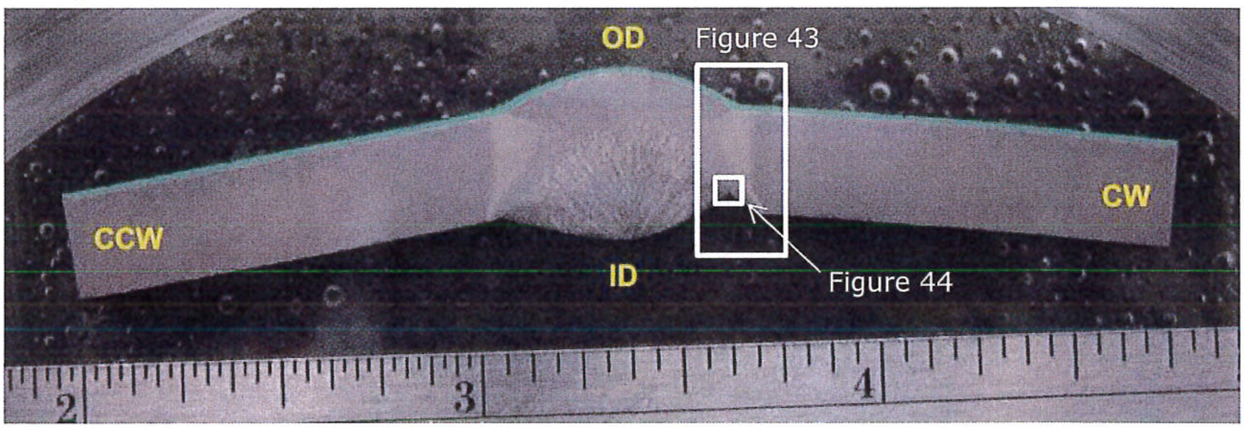


Figure 39. Photograph of the mounted cross-section (Mount M2) removed from MPI Indications 2 (CW) of the ruptured joint, away from the rupture; 23.83 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

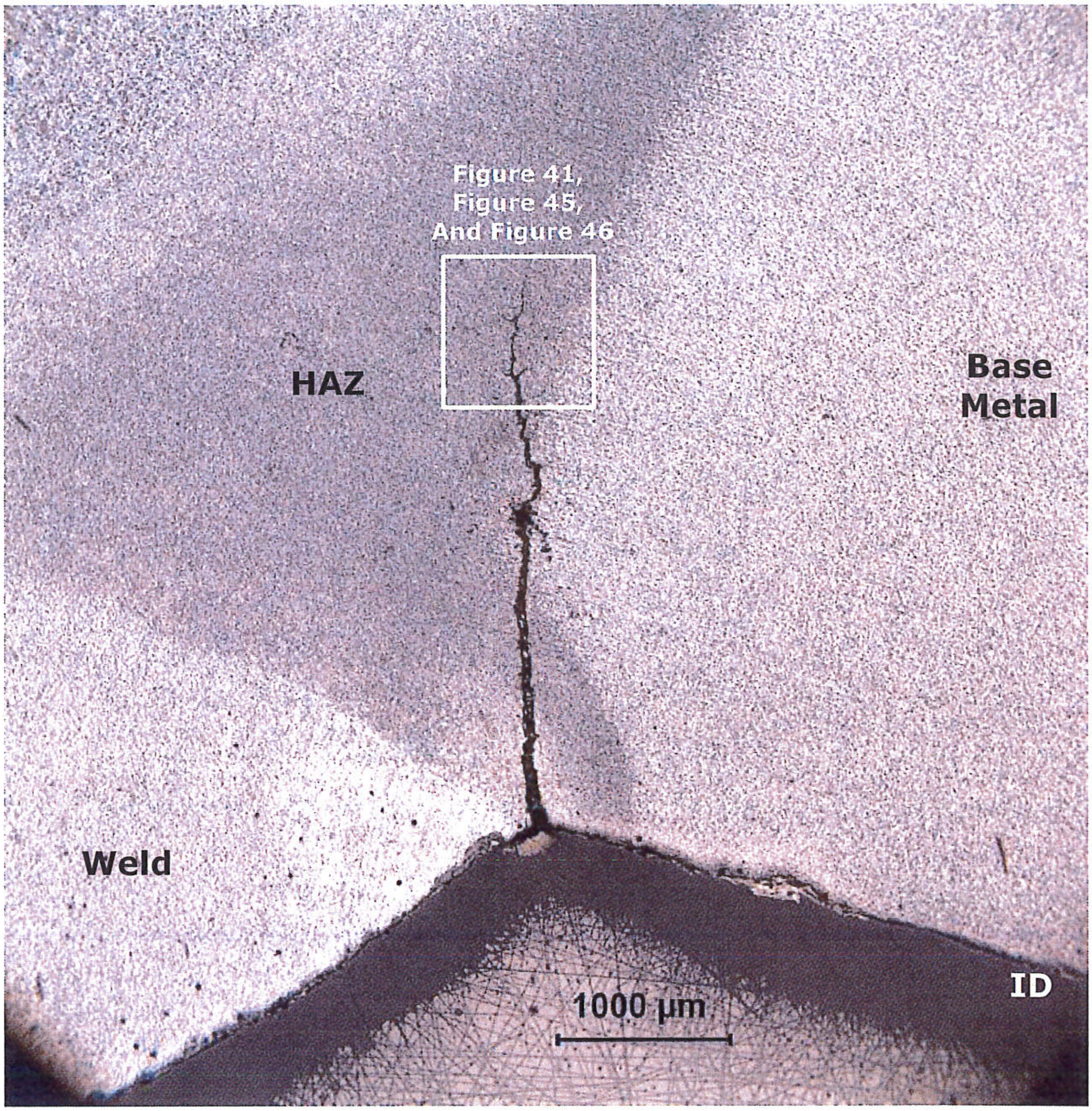


Figure 40. Photomicrograph of Mount M1 (MPI Indication 1a) showing crack at weld toe from ID surface on clockwise (CW) side of the seam weld; mirror image of area indicated in Figure 38. 4% Nital Etch.

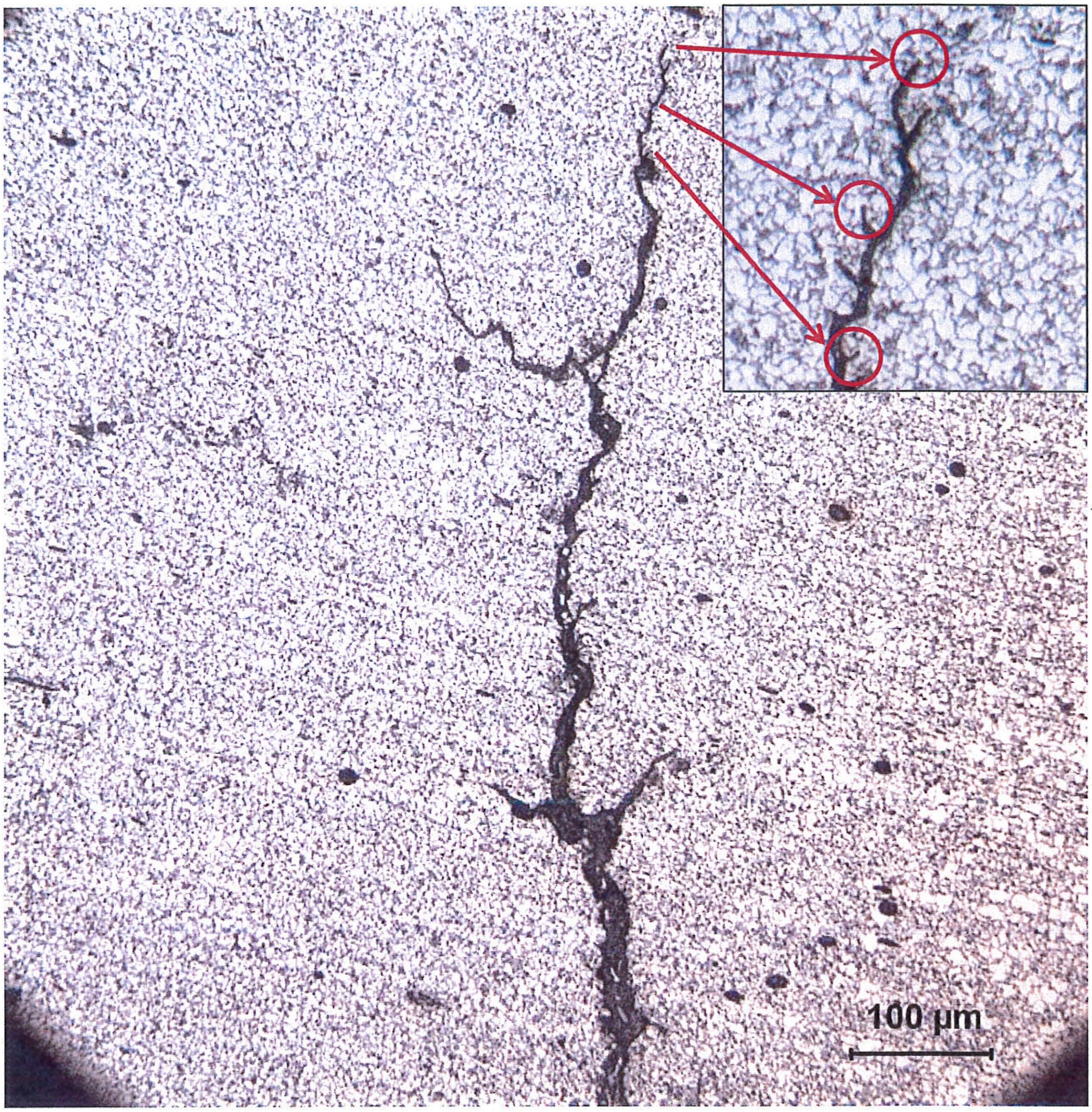


Figure 41. Photomicrograph of Mount M1 (MPI Indication 1a) showing crack tip on clockwise (CW) side of the seam weld; area indicated in Figure 40. 4% Nital Etch. Inset photo shows close-up of transgranular morphology at crack tip.

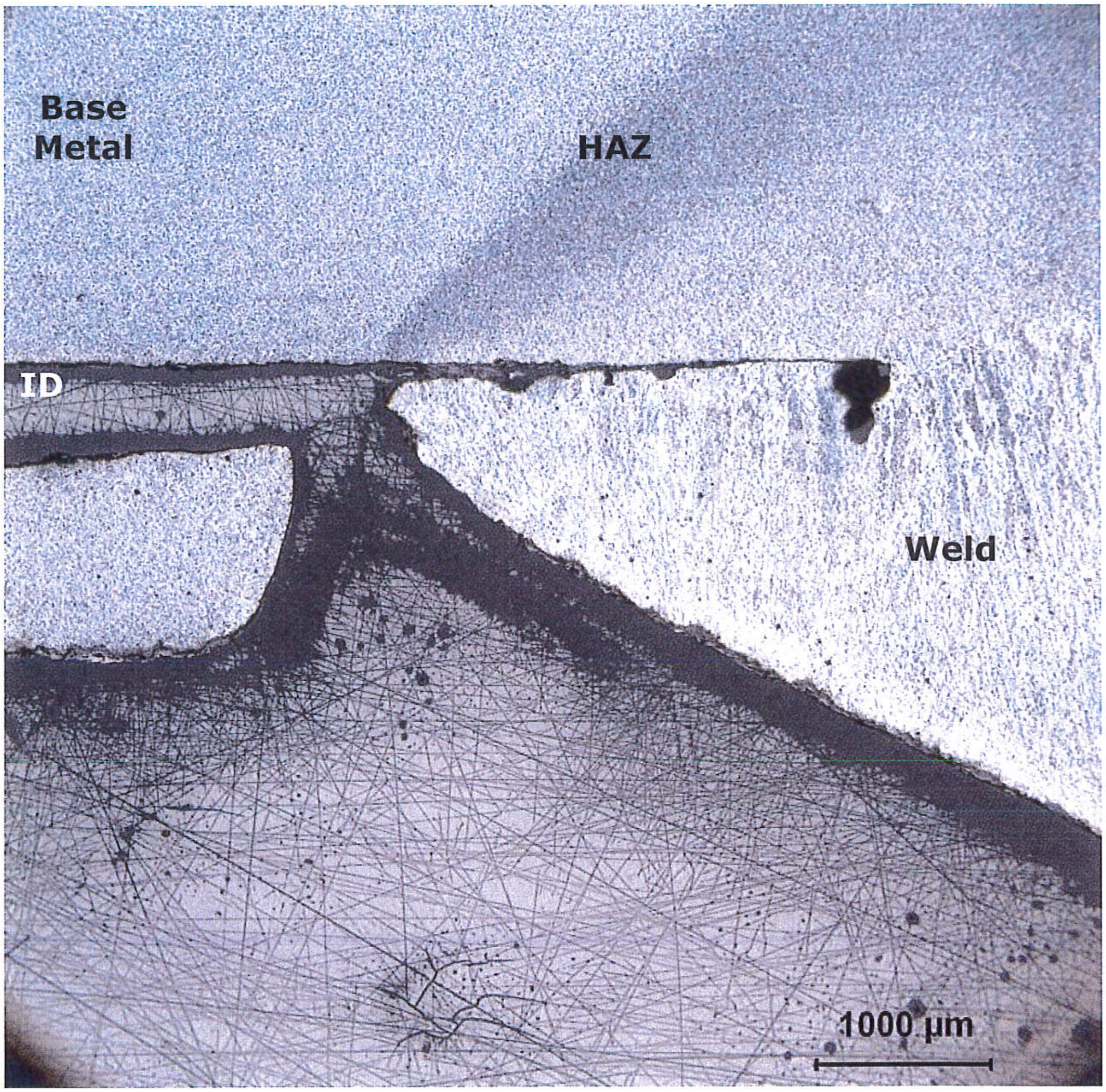


Figure 42. Photomicrograph of Mount M1 (MPI Indication 1b) showing overlap of weld bead on ID surface, counterclockwise (CCW) side of the seam weld; mirror image of area indicated in Figure 38. 4% Nital Etch.

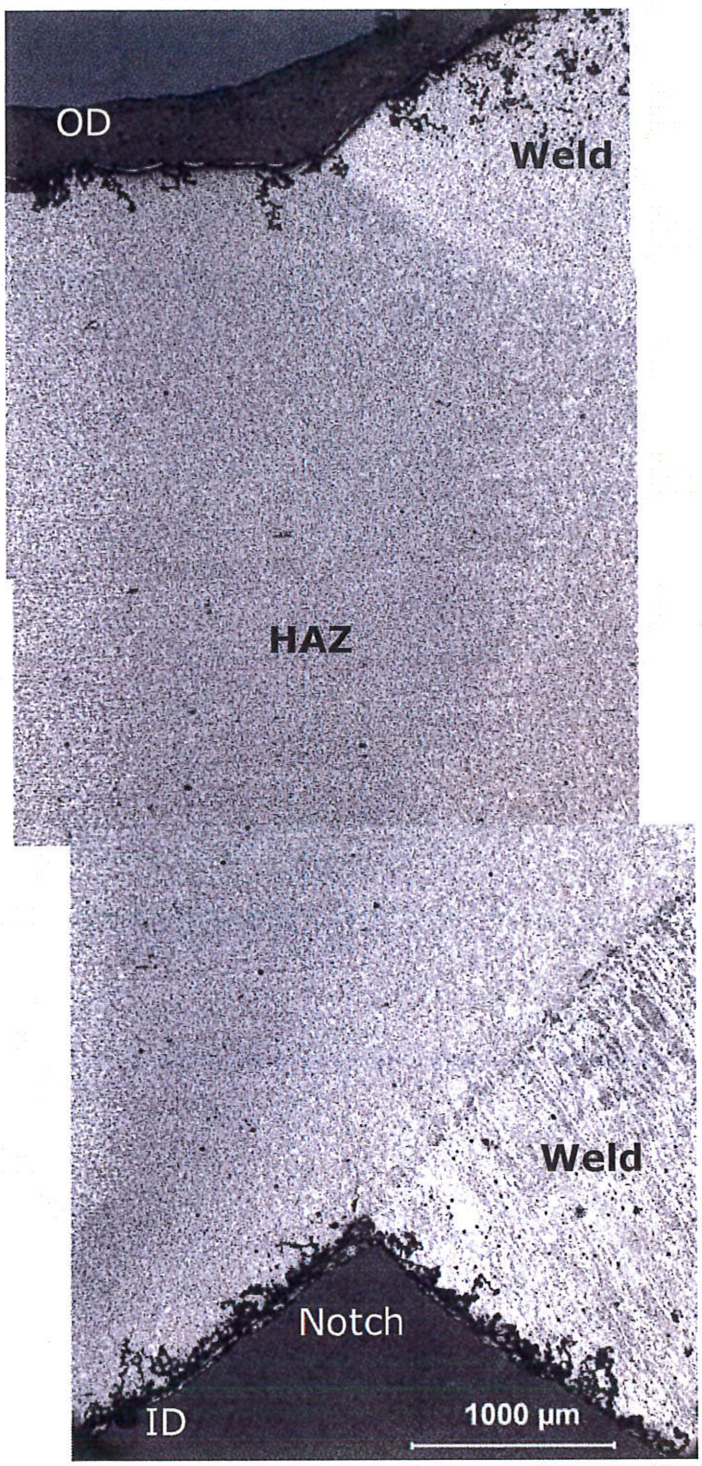
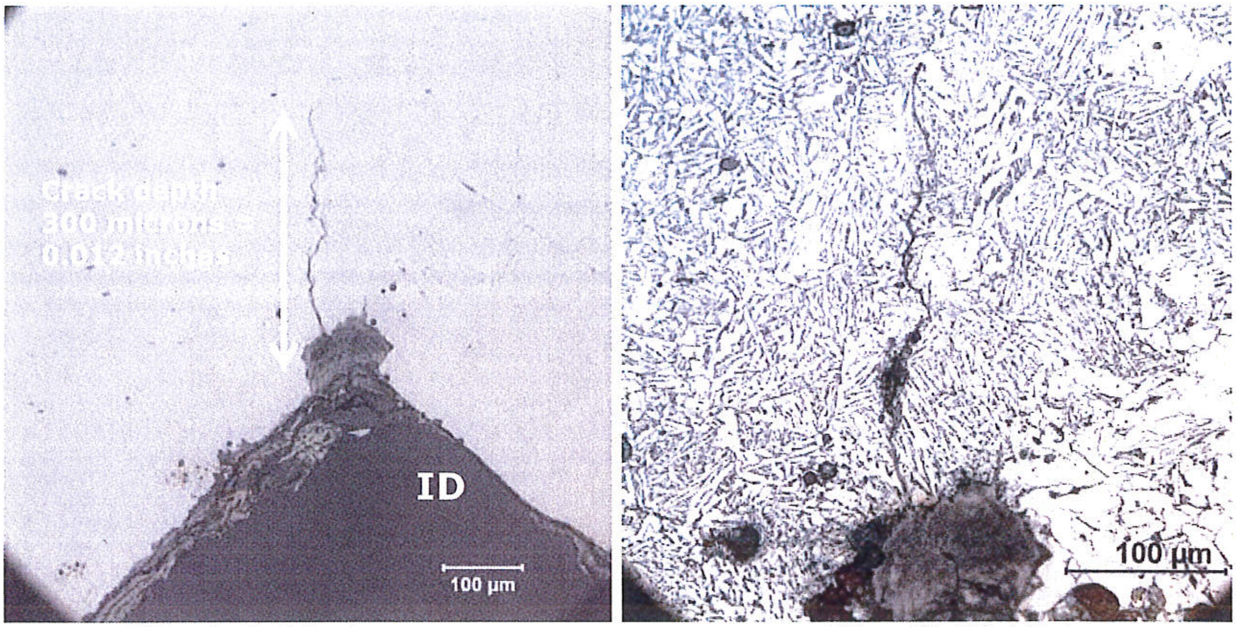


Figure 43. Photomicrograph of Mount M2 (MPI Indication 2), clockwise (CW) side of the weld, showing a notch from undercut at the weld toe; mirror image of area indicated in Figure 39. 4% Nital Etch.



M2 – As Polished M2 – 4% Nital Etch

Figure 44. Photomicrographs of Mount M2 (MPI Indication 2) showing crack at weld toe from ID surface on clockwise (CW) side of the seam weld; mirror images of area indicated in Figure 39.

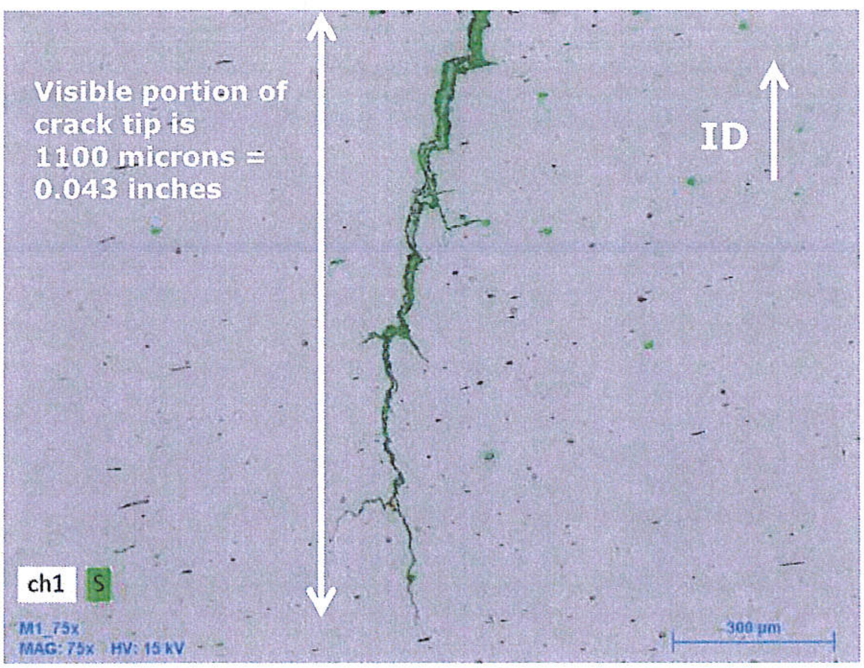


Figure 45. EDS map of Mount M1 (MPI Indication 1a) at crack shown in Figure 40, showing presence of sulfur at tip of the crack that started at weld toe from ID surface on clockwise (CW) side of the seam weld.

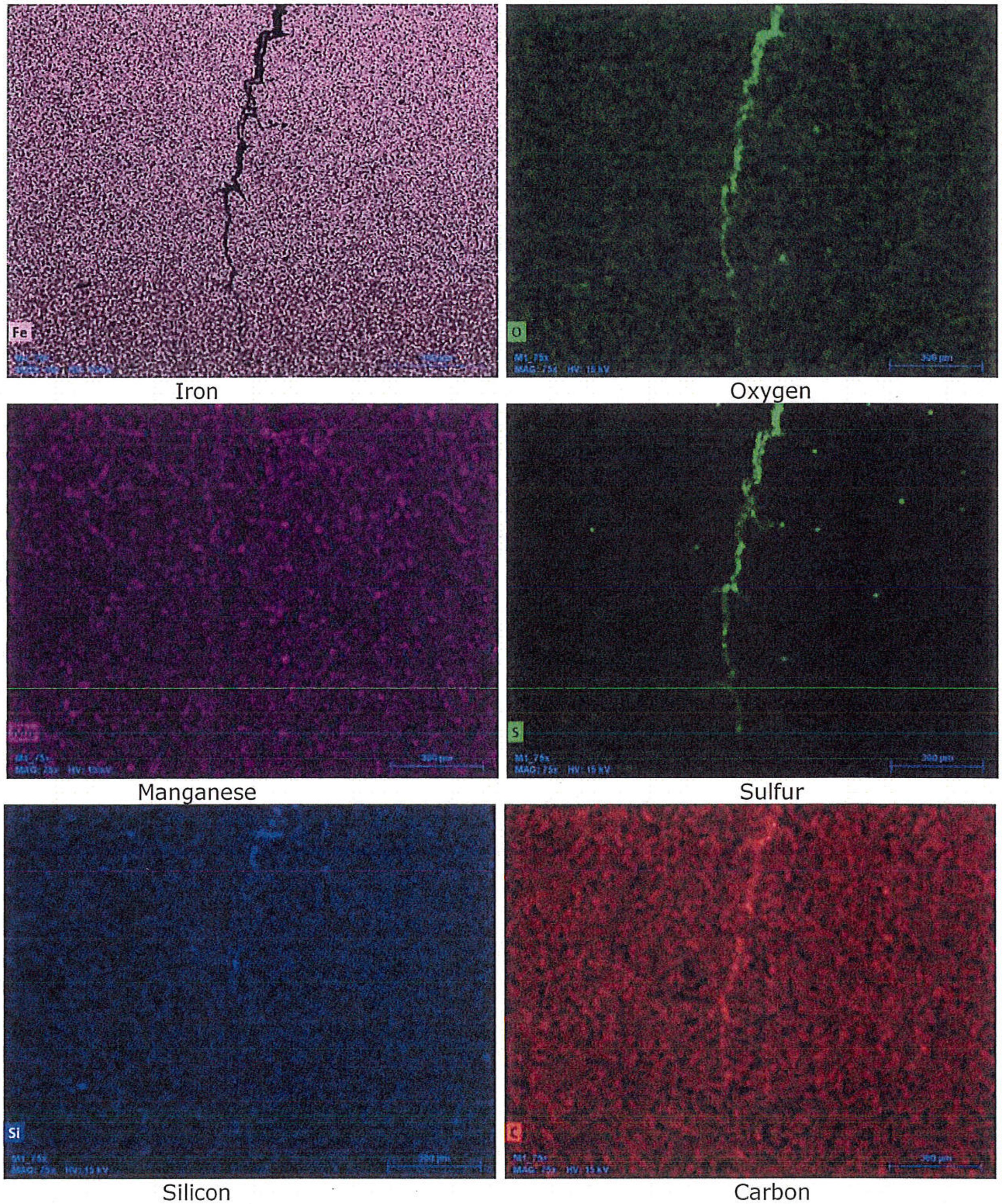


Figure 46. EDS map of Mount M1 (MPI Indication 1a) at crack shown in Figure 40, showing distribution of Fe, O, Mn, S, Si, and C at tip of the crack that started at weld toe from ID surface on clockwise (CW) side of the seam weld.

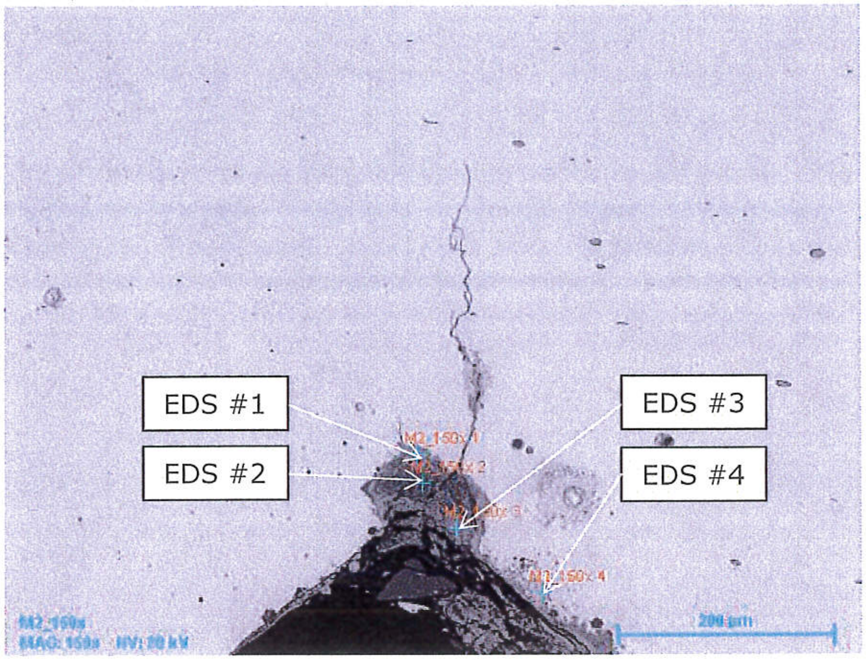


Figure 47. EDS measurement locations on Mount M2 (results shown in Table 5; also refer back to Figure 44), at weld toe crack with pit and corrosion product, from ID surface on counterclockwise (CCW) side of the seam weld.

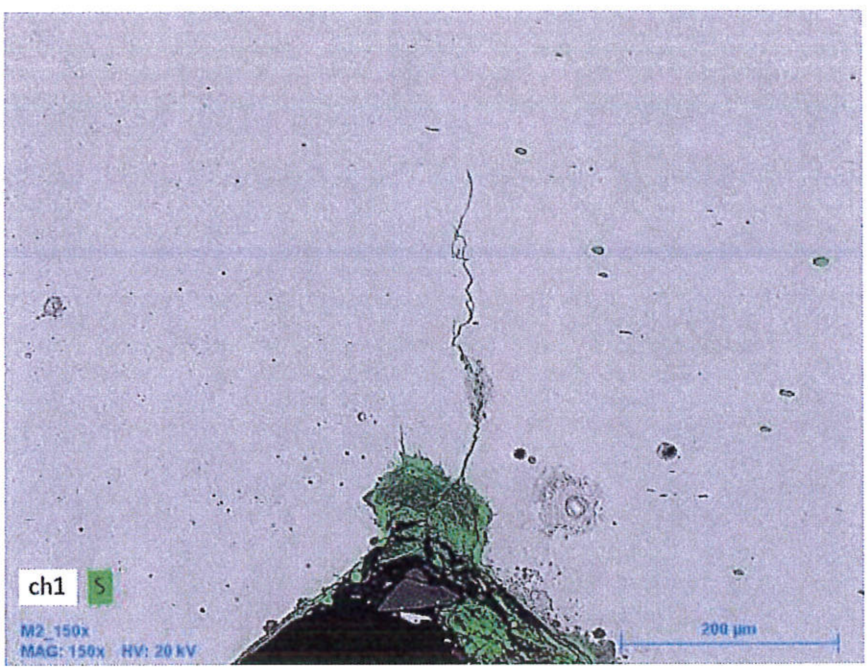


Figure 48. EDS map of Mount M2 (MPI Indication 2) at crack shown in Figure 47, showing distribution of sulfur.

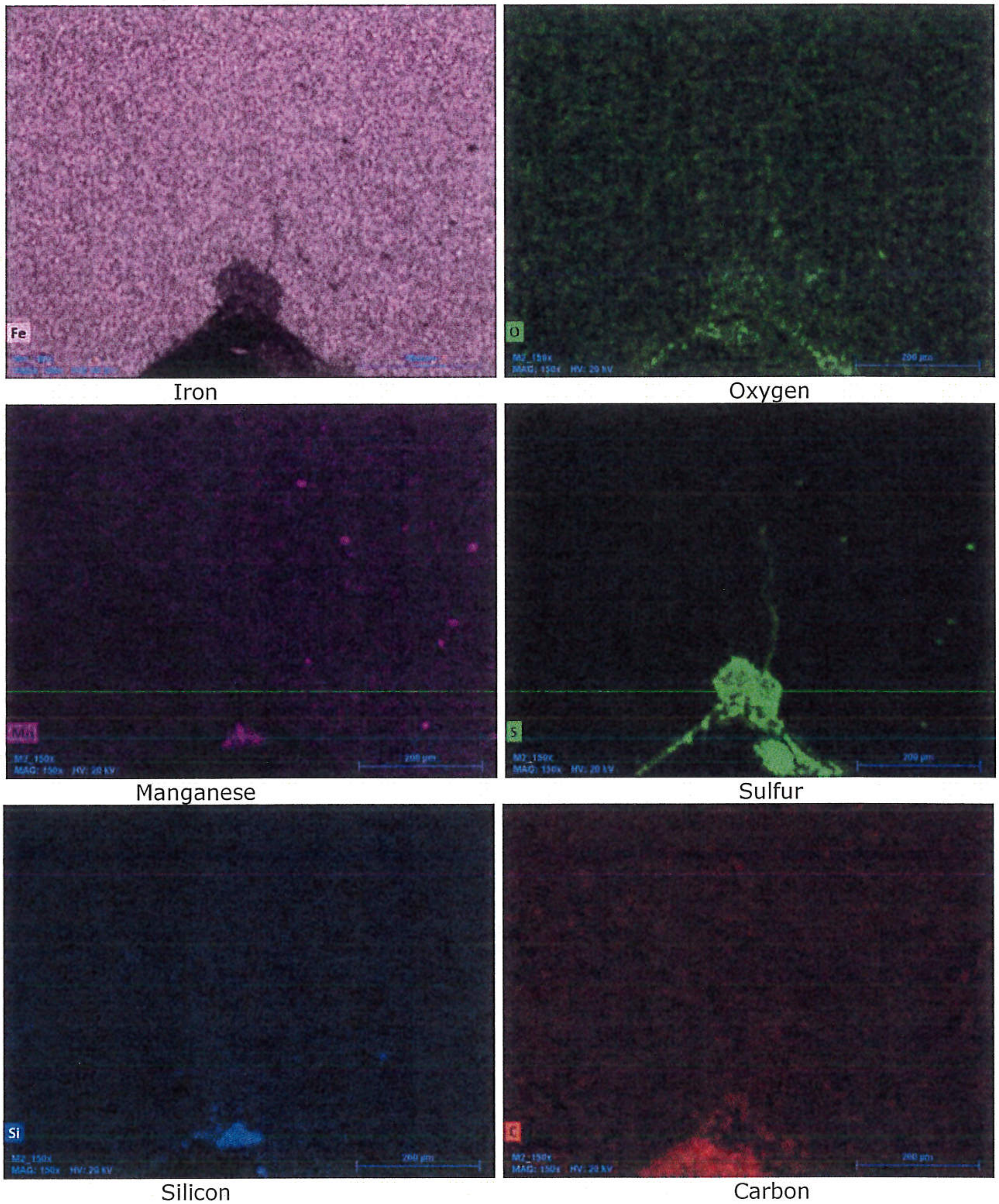
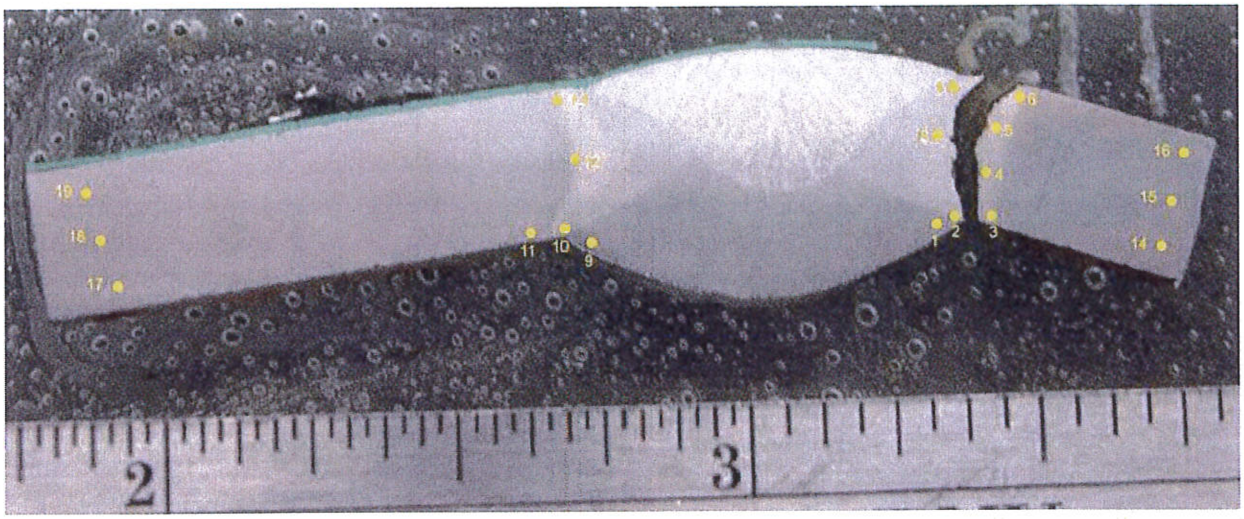
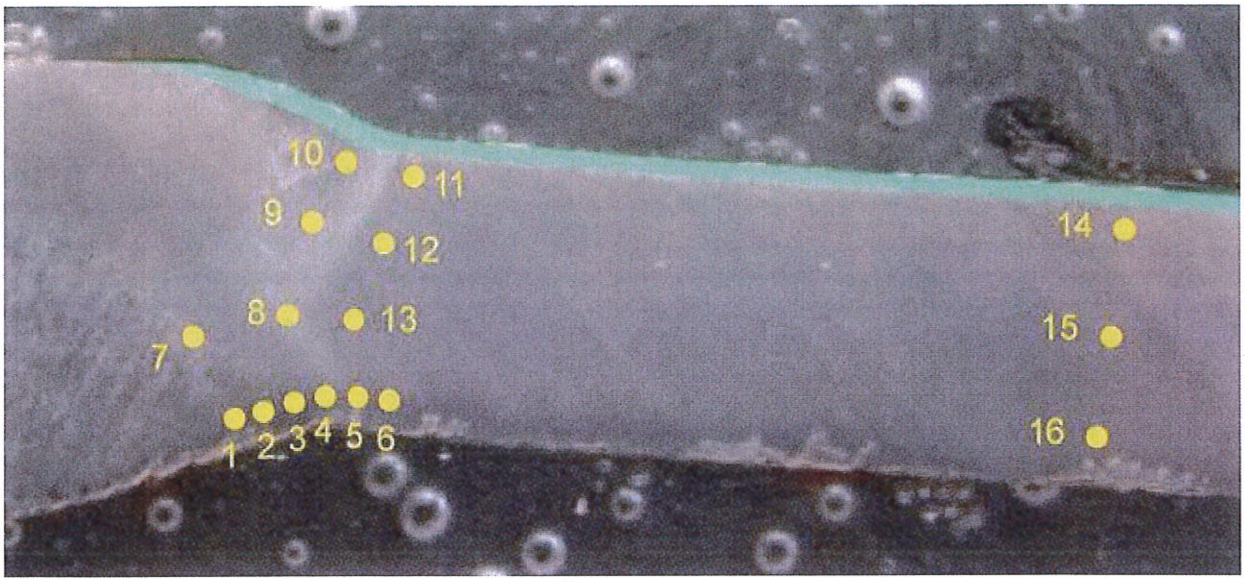


Figure 49. EDS map of Mount M2 (MPI Indication 2) at crack shown in Figure 47, showing distribution of Fe, O, Mn, S, Si, and C.



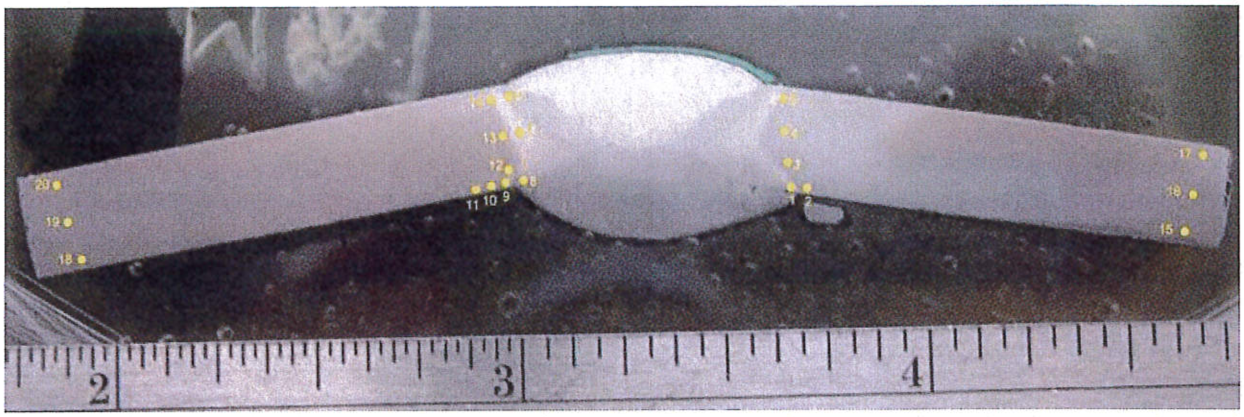
Measurement Location	Hardness (HV)	
	Mount M5 16.13 ft from U/S GW	Mount M6 16.33 ft from U/S GW
1	190.3	192.5
2	218.1	187.6
3	204.1	201.7
4	206.5	218.8
5	210.9	209.1
6	215.5	228.5
7	204.1	206.0
8	216.1	183.4
9	163.1	176.4
10	182.9	210.3
11	201.7	214.8
12	182.9	190.9
13	207.8	190.9
14	212.2	211.6
15	197.0	208.4
16	191.4	224.3
17	227.8	214.8
18	206.5	195.3
19	180.4	180.9

Figure 50. Results of hardness measurements at various locations on Mount M5 (Figure 24) and Mount M6 (Figure 25). Mount M5 shown above; measurements performed at similar locations on Mount M6.



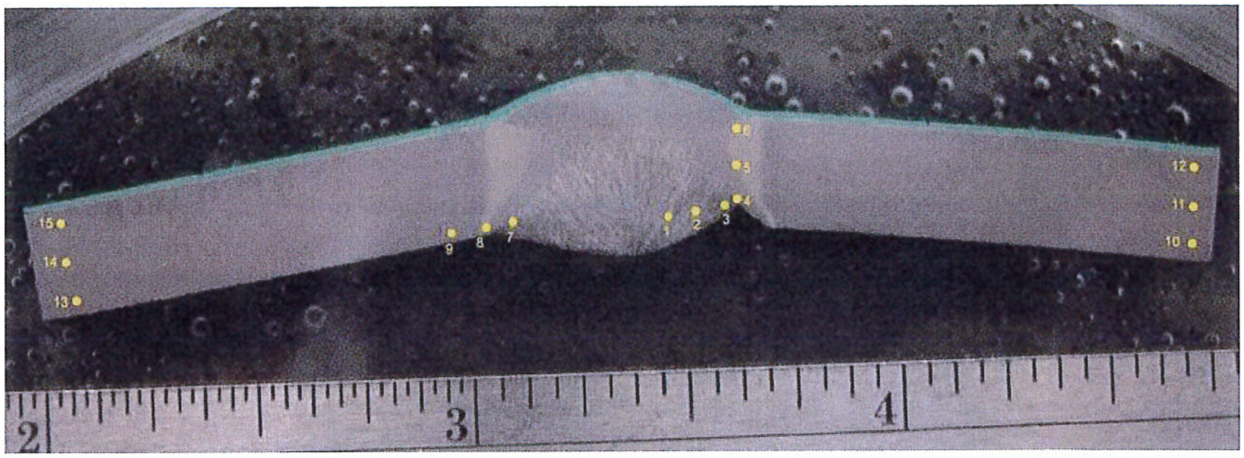
Measurement Location	Hardness (HV)		
	Mount M3 D/S joint	Mount M4 U/S joint	Mount M7 Failed joint
1	183.4	213.4	193.1
2	213.5	235.1	196.5
3	195.3	226.4	218.1
4	207.8	226.4	220.1
5	205.3	227.8	225.0
6	201.7	214.2	214.2
7	205.3	216.8	214.2
8	172.1	214.2	214.2
9	201.1	205.3	200.5
10	214.8	192.0	191.9
11	201.1	227.8	204.1
12	190.3	218.1	210.3
13	180.4	199.9	210.3
14	181.4	220.1	201.1
15	183.4	205.3	193.1
16	168.9	212.9	193.1

Figure 51. Results of hardness measurements taken at representative locations on Mount M3 (Figure 36), Mount M4 (Figure 37), and Mount M7 (Figure 35). Mount M3 shown above; measurements performed at similar locations on Mount M4 and Mount M7.



Measurement Location	Hardness (HV) Mount M1 MPI Indications 1a/1b
1	188.7
2	211.6
3	208.4
4	200.5
5	211.6
6	184.5
7	194.2
8	201.7
9	174.0
10	163.1
11	166.5
12	197.0
13	197.7
14	214.8
15	203.2
16	187.6
17	214.2
18	227.1
19	197.0
20	183.4

Figure 52. Results of hardness measurements at various locations on Mount M1.



Measurement Location	Hardness (HV)
	Mount M2
1	179.9
2	192.0
3	210.3
4	207.2
5	197.6
6	196.5
7	199.3
8	196.5
9	204.1
10	211.6
11	180.9
12	196.7
13	194.2
14	190.1
15	191.4

Figure 53. Results of hardness measurements at various locations on Mount M2.

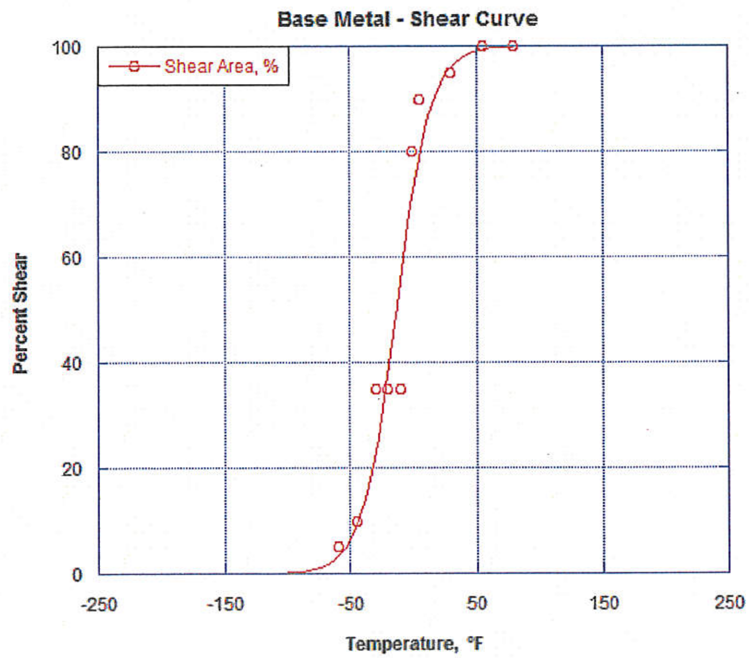


Figure 54. Percent shear from Charpy V-notch tests as a function of temperature for transverse base metal specimens removed from the pipe joint that ruptured.

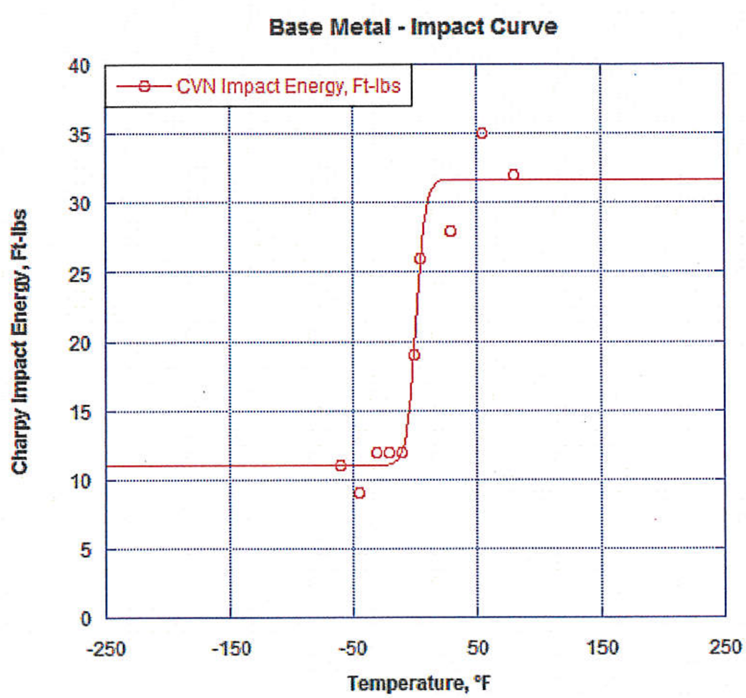


Figure 55. Charpy V-notch impact energy as a function of temperature for transverse base metal specimens removed from the pipe joint that ruptured.

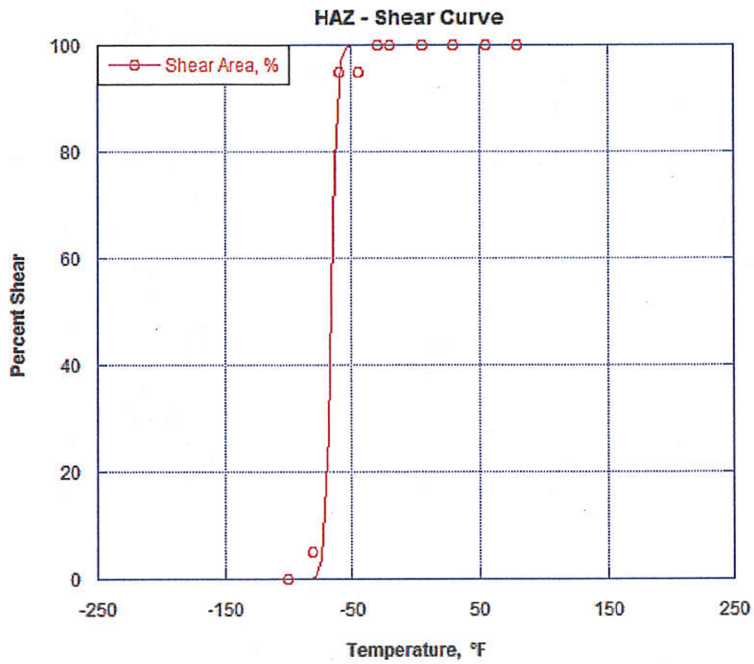


Figure 56. Percent shear from Charpy V-notch tests as a function of temperature for transverse seam weld (HAZ) specimens removed from the pipe joint that ruptured.

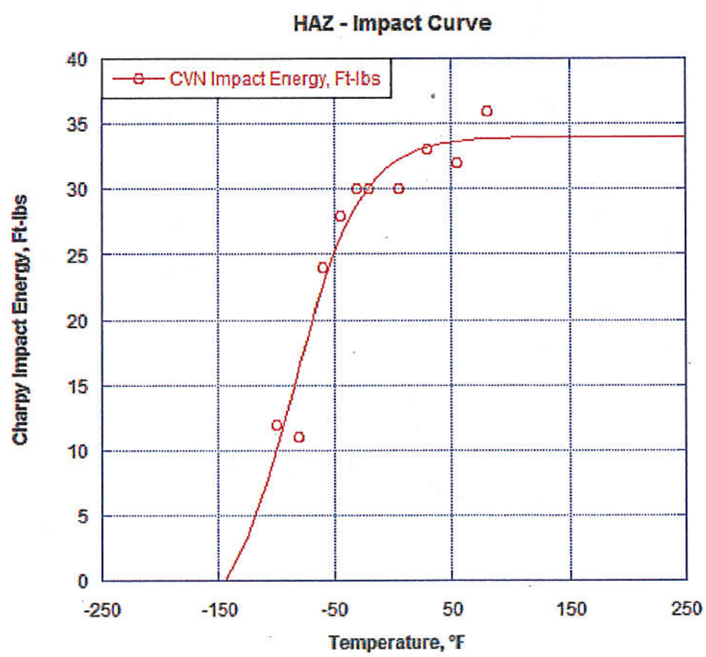


Figure 57. Charpy V-notch impact energy as a function of temperature for transverse seam weld (HAZ) specimens removed from the pipe joint that ruptured.

APPENDIX A

DSAW Measurements

Rupture Location

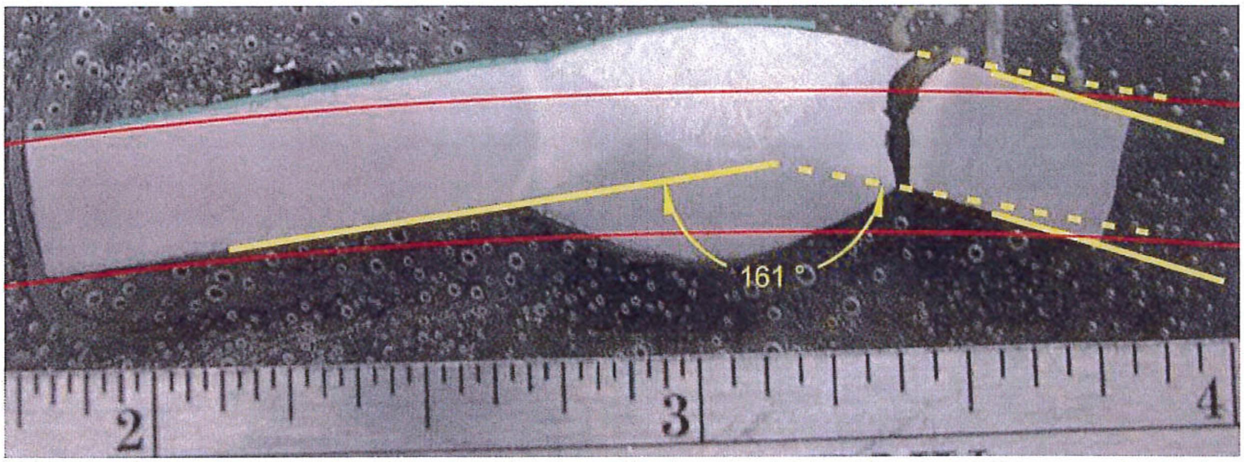


Figure A1. Photograph of the mounted cross-section (Mount M5) removed from Rupture Origin, 16.13 feet from the U/S GW.

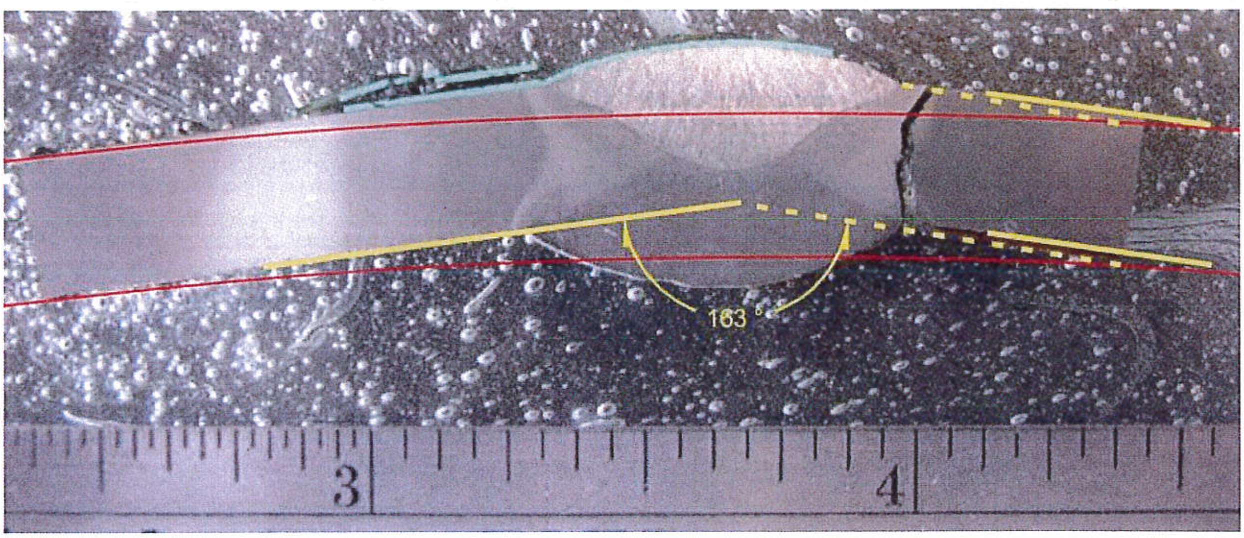


Figure A2. Photograph of the mounted cross-section (Mount M6) removed from Rupture Origin, 16.33 feet from the U/S GW.

Reference Locations

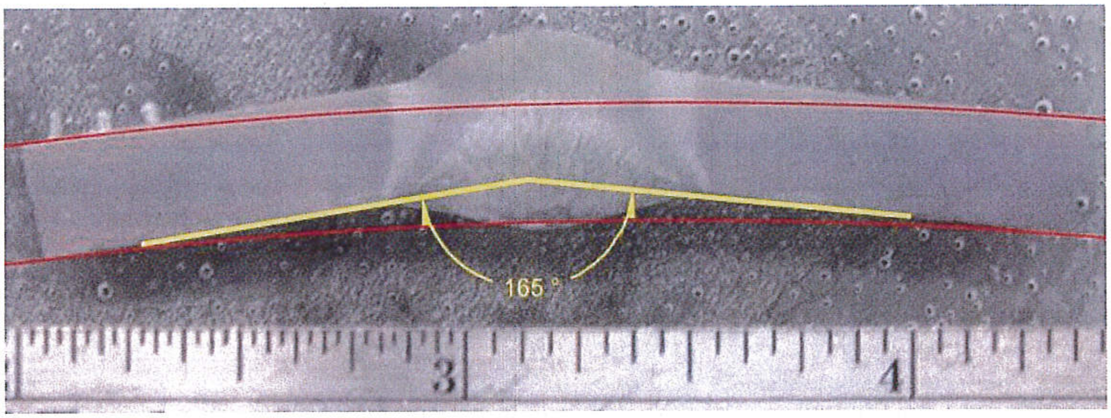


Figure A3. Photograph of the mounted cross-section (Mount M7) removed from Failed Joint, Away from the Rupture, 21.16 feet from the U/S GW.

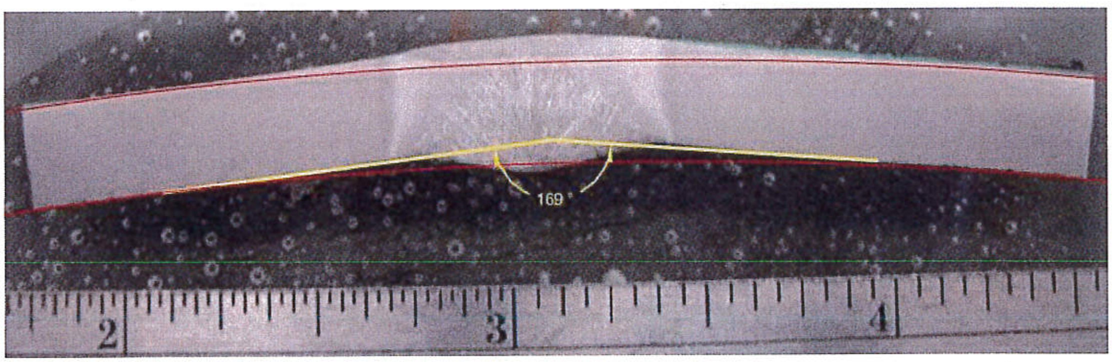


Figure A4. Photograph of the mounted cross-section (Mount M4) removed from U/S Joint, -1.54 ft from the U/S GW.

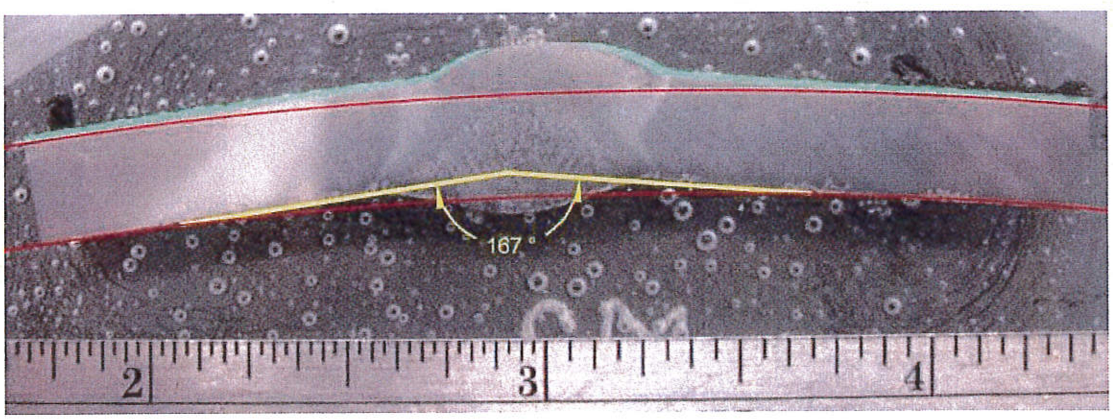


Figure A5. Photograph of the mounted cross-section (Mount M3) removed from D/S Joint, 28.19 feet from the U/S GW.

MPI Indications

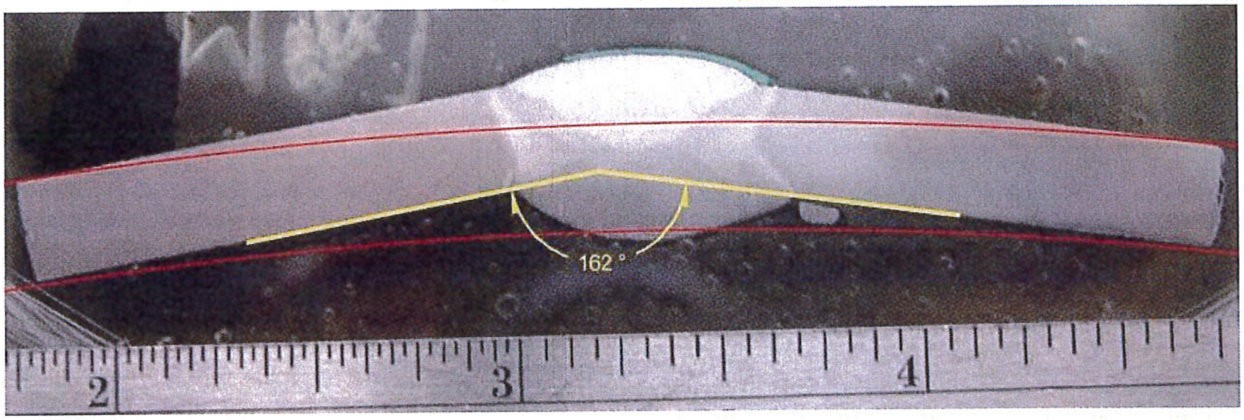


Figure A6. Photograph of the mounted cross-section (Mount M1) removed from MPI Indications 1a/1b, 18.81 feet from the U/S GW.

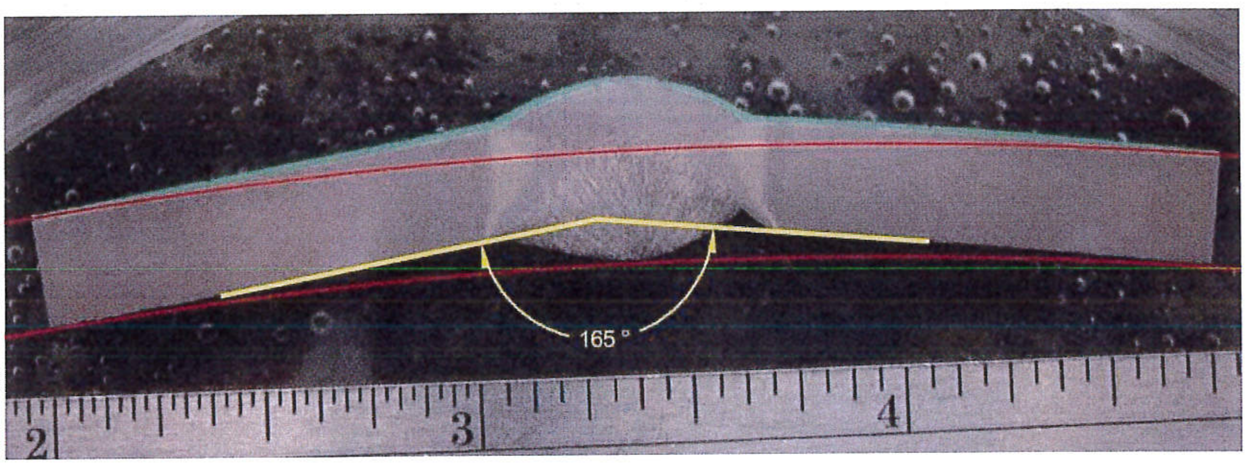


Figure A7. Photograph of the mounted cross-section (Mount M2) removed from MPI Indication 2, 23.83 feet from the U/S GW.

APPENDIX B

CorLAS™ Analysis

APPENDIX B

Description of CorLAS™

The CorLAS™ computer program was developed by Det Norske Veritas (U.S.A.), Inc. (formerly CC Technologies) to evaluate crack-like flaws in pipelines based on inelastic fracture mechanics. Using the effective area of the actual, measured crack length-depth profile, an equivalent semi-elliptical surface flaw is modeled and used to compute the effective stress and the applied value of J for internal pressure loading. The effective stress and applied J are then compared with the flow strength (σ_{fs}) and fracture toughness (J_C), respectively, to predict the failure pressure.

The program also contains a similar inelastic fracture mechanics analysis for through-wall flaws. The fracture toughness of the steel can be estimated from Charpy data or measured by means of a J_{IC} test. In the most recent version of CorLAS™, the fracture toughness analysis automatically checks for plastic instability and only the fracture toughness curve needs to be considered for crack-like flaws. The actual tensile and Charpy properties of the pipe joint, measured from the samples removed, can be used for the critical leak/rupture length calculation.

Case 1: Measured mechanical base-metal properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue).

Shell SVJ 24"	Semi-Elliptical Flaw Profile			
	Base Metal			
	Maximum Operating Pressure (psig)	936		
	UTS (psi)	87800		
	YS (psi)	70300		
	FS (psi)	79050		
	E (ksi)	29500		
	nexp	0.089		
	Jc (lb/in)	3068		
	Thin-wall (OD) formula for hoop stress			
	Tmat	49.3		
	OD (in.)	24		
	Wall Thickness (in.)	0.260		
Summary of Results for Effective Area Method				
	Flaw: Start (in.)	0.50		
	Length (in.)	6.75		
	Area (in.^2)	0.464		
	Depth (in.) Maximum	0.097		
	Equivalent Flaw	0.088		
	For Design Factor	0.72		
	Design Pressure (psig)	1096.68		
	Failure Stress (psi)	65598		
	Failure Pressure (psig)	1421.28		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	1023.32		
Critical and Safe Pressure for a Crack				
	At operating pressure: J (lb/in)	43.3	T	4.9
	For Jc (lb/in)	3068.0	Tmat	49.3
	Predicted Critical Pressure (psig)	1413.18		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	1017.49		
	Based on J Fracture Toughness (Jc) criterion			
	Flaw: Start (in.)	0.50		
	Length (in.)	6.75		
	Area (in.^2)	0.464		
	Depth (in.): Maximum	0.097		
	Equivalent Flaw	0.088		

Case 2: Measured mechanical base-metal properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue) + Region 2 (Step-Wise Cracking).

Shell SVJ 24"	Semi-Elliptical Flaw Profile			
	Base Metal			
	Maximum Operating Pressure (psig)	936		
	UTS (psi)	87800		
	YS (psi)	70300		
	FS (psi)	79050		
	E (ksi)	29500		
	nexp	0.089		
	Jc (lb/in)	3068		
	Thin-wall (OD) formula for hoop stress			
	Tmat	49.3		
	OD (in.)	24		
	Wall Thickness (in.)	0.260		
Summary of Results for Effective Area Method				
	Flaw: Start (in.)	1.00		
	Length (in.)	5.00		
	Area (in.^2)	1.010		
	Depth (in.) Maximum	0.210		
	Equivalent Flaw	0.234		
	For Design Factor	0.72		
	Design Pressure (psig)	1096.68		
	Failure Stress (psi)	35994		
	Failure Pressure (psig)	779.86		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	561.5		
Critical and Safe Pressure for a Crack				
	At operating pressure: J (lb/in)	37199.3	T	-
	For Jc (lb/in)	3068.0	Tmat	49.3
	Predicted Critical Pressure (psig)	658.13		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	473.85		
	Based on J Fracture Toughness (Jc) criterion			
	Flaw: Start (in.)	1.75		
	Length (in.)	3.50		
	Area (in.^2)	0.684		
	Depth (in.): Maximum	0.210		
	Equivalent Flaw	0.249		

Case 3: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue).

Shell SVJ 24"	Semi-Elliptical Flaw Profile			
	HAZ			
	Maximum Operating Pressure (psig)	936		
	UTS (psi)	85700		
	YS (psi)	70300		
	FS (psi)	78000		
	E (ksi)	29500		
	nexp	0.083		
	Jc (lb/in)	3000		
	Thin-wall (OD) formula for hoop stress			
	Tmat	49.7		
	OD (in.)	24		
	Wall Thickness (in.)	0.260		
Summary of Results for Effective Area Method				
	Flaw: Start (in.)	0.50		
	Length (in.)	6.75		
	Area (in.^2)	0.464		
	Depth (in.) Maximum	0.097		
	Equivalent Flaw	0.088		
	For Design Factor	0.72		
	Design Pressure (psig)	1096.68		
	Failure Stress (psi)	64726		
	Failure Pressure (psig)	1402.41		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	1009.73		
Critical and Safe Pressure for a Crack				
	At operating pressure: J (lb/in)	41.7	T	4.7
	For Jc (lb/in)	3000.0	Tmat	49.7
	Predicted Critical Pressure (psig)	1394.41		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	1003.97		
	Based on J Fracture Toughness (Jc) criterion			
	Flaw: Start (in.)	0.50		
	Length (in.)	6.75		
	Area (in.^2)	0.464		
	Depth (in.): Maximum	0.097		
	Equivalent Flaw	0.088		

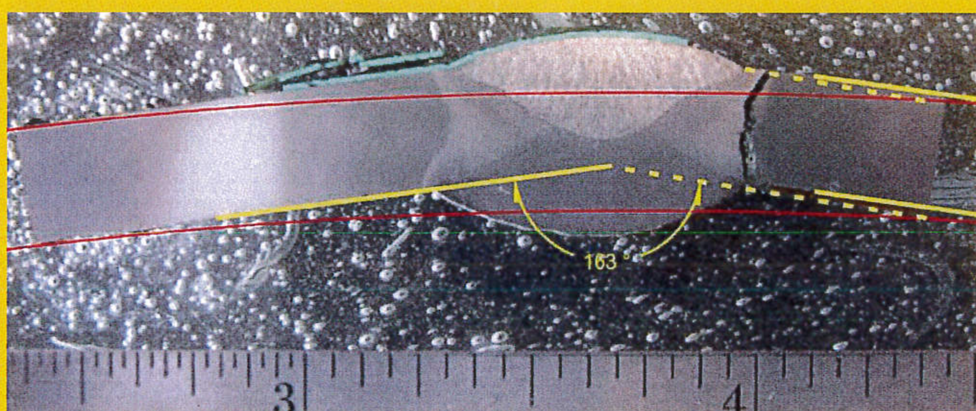
Case 4: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue) + Region 2 (Step-Wise Cracking).

Shell SVJ 24"	Semi-Elliptical Flaw Profile			
	HAZ			
	Maximum Operating Pressure (psig)	936		
	UTS (psi)	85700		
	YS (psi)	70300		
	FS (psi)	78000		
	E (ksi)	29500		
	nexp	0.083		
	Jc (lb/in)	3000		
	Thin-wall (OD) formula for hoop stress			
	Tmat	49.7		
	OD (in.)	24		
	Wall Thickness (in.)	0.260		
Summary of Results for Effective Area Method				
	Flaw: Start (in.)	1.00		
	Length (in.)	5.50		
	Area (in.^2)	1.010		
	Depth (in.) Maximum	0.210		
	Equivalent Flaw	0.234		
	For Design Factor	0.72		
	Design Pressure (psig)	1096.68		
	Failure Stress (psi)	35516		
	Failure Pressure (psig)	769.50		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	554.04		
Critical and Safe Pressure for a Crack				
	At operating pressure: J (lb/in)	20361.8	T	5938.4
	For Jc (lb/in)	3290.3	Tmat	54.5
	Predicted Critical Pressure (psig)	663.78		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	477.92		
	Based on J Fracture Toughness (Jc) criterion			
	Flaw: Start (in.)	1.25		
	Length (in.)	4.25		
	Area (in.^2)	0.817		
	Depth (in.): Maximum	0.210		
	Equivalent Flaw	0.245		

ABOUT DNV GL

Driven by our purpose of safeguarding life, property, and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter, and greener.

SJV 24-INCH MAY 20TH, 2016 LOPC RCA REPORT



AGENDA

- Summary of RCA
- Timeline of Events
- Summary of the Failure Analysis Results
- Summary Cause and Effect Diagram
- Explanation of the Metallurgical Causes
- ILI Vendor Selection and Performance
- Recommendations
- Background
  - DNV GL Failure Analysis Report
  - Detailed Timeline
  - Cause and Effects Diagram

SUMMARY OF THE RCA

On May 20th, 2016, a rupture occurred on the Tracy to Windmill section of the SJV pipeline system. This rupture occurred due to a fatigue crack that developed and grew to failure and was not reported by the UT-C ILI survey.

The fatigue crack developed and grew to failure during transportation and/or in-service. The peaked geometry of the longitudinal seam weld, operational pressure cycling, inclusions in the pipe steel, and potentially an environmental factor played a role in the growth of the crack.

A feature was "detected, identified and... classified as a crack-like in long seam" at the location of failure in the automatic report following the UT-C survey. During manual review of the data by Rosen, "an incorrect amplitude was selected." Because of this "the Analyst overruled the [automated] call with the lower depth of 0.013 inch" (5%). This ultimately led to Rosen not reporting the feature.

TIMELINE OF EVENTS - 1

- 1982 – Pipe was manufactured by ARMCO in Houston, TX for Columbia Gas and shipped to Northeastern US
- 1988 - Pipe was purchased by Texaco from Columbia Gas and shipped from the Northeastern US to Coalinga, California
- 1989 – Pipe was installed at Tracy to Windmill Farms (3.05 miles)
  - Also installed at Coalinga to Mack Hill (3.4 miles of 5.9 mile segment) and Butts Road to Gustine (6.1 miles of 7.2 mile segment)
- April 1990 – Pipeline hydrotested to 1,181 psig, held for four hours
- 1998 to 2015 – Multiple MFL and caliper surveys performed
- 6/6/1998 - 02:35 PST – Pipe failure approximately one mile downstream of Tracy in pipe body
- 5/25/15 – Pump Fire at Tracy
  - Heat and pressure from the incident is not thought to have affected the pipeline segment

TIMELINE OF EVENTS - 2

- 9/16/15 at 23:35 CDT – Rupture occurred on the 24″ section of piping 1,829 feet downstream of Tracy Station
  - Subsequent failure analysis determined the pipe section ruptured at a preexisting fatigue crack that initiated at the toe of the double submerged arc weld (DSAW)
- 9/21/15 - Pipeline operation commenced at a temporarily reduced pressure of to 724 psig
  - 80% of 905 psig the pressure at the time of the 9/16/2015 LOPC
- 12/3/2015 – Rosen MFL-C survey performed on the pipeline
- 12/4/2015 - Rosen UT-C survey performed on the pipeline
- 3/7/2016 – Final MFL-C report provided to SPLC showing:
  - No crack-like or other anomalies necessitating immediate action or any additional repairs required per SPLC Anomaly Response Table.

TIMELINE OF EVENTS - 3

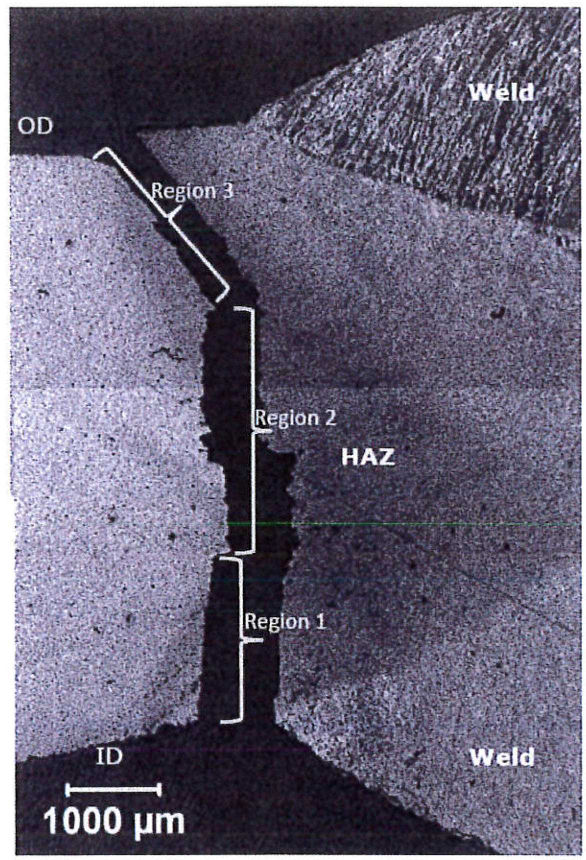
- 4/11/2016 – Draft Preliminary UT-C Report received from Rosen
  - Resulted in two excavations based on 180-day conditions from the SPLC Anomaly Response Table
- 4/25/2016 – Preliminary UT-C report received from Rosen.
  - No additional features reported that met the SPLC Anomaly Response Table
- 5/2/2016 – Final UT-C report provided to SPLC showing:
  - No crack anomalies necessitating immediate action per the SPLC Anomaly Response Table
  - Two conditions reported by Rosen classified as 180 day conditions by SPLC
    - Scheduled for excavation based on 4/11/2016 Draft Preliminary Report

TIMELINE OF EVENTS - 4

- 5/9/2016 – Based on the MFL-C and UT-C surveys confirming the absence of any actionable defects, the recommendation was made by SPLC Engineering to remove the operating pressure reductions on three North Heavy segments with 24-inch Armco pipe.
- 5/16/2016 – Statement of Fitness to remove the 20% pressure reduction was approved
- 5/17/2016 – 20% pressure reduction was removed and original 936 psig MOP re-instated
- 5/20/2016 - 00:35:55 PDT – Pipeline failed 4,013 feet downstream of Tracy Station
- 5/22/2016 – Failed pipe joint was replaced with 24-inch pipe
- 6/9/2016 - Spike (1,170 psig) and 8-hour hold (1,070 psig) hydrotest was successful
- 7/19/2016 – Pipeline restarted at a new MOP of 850 psig

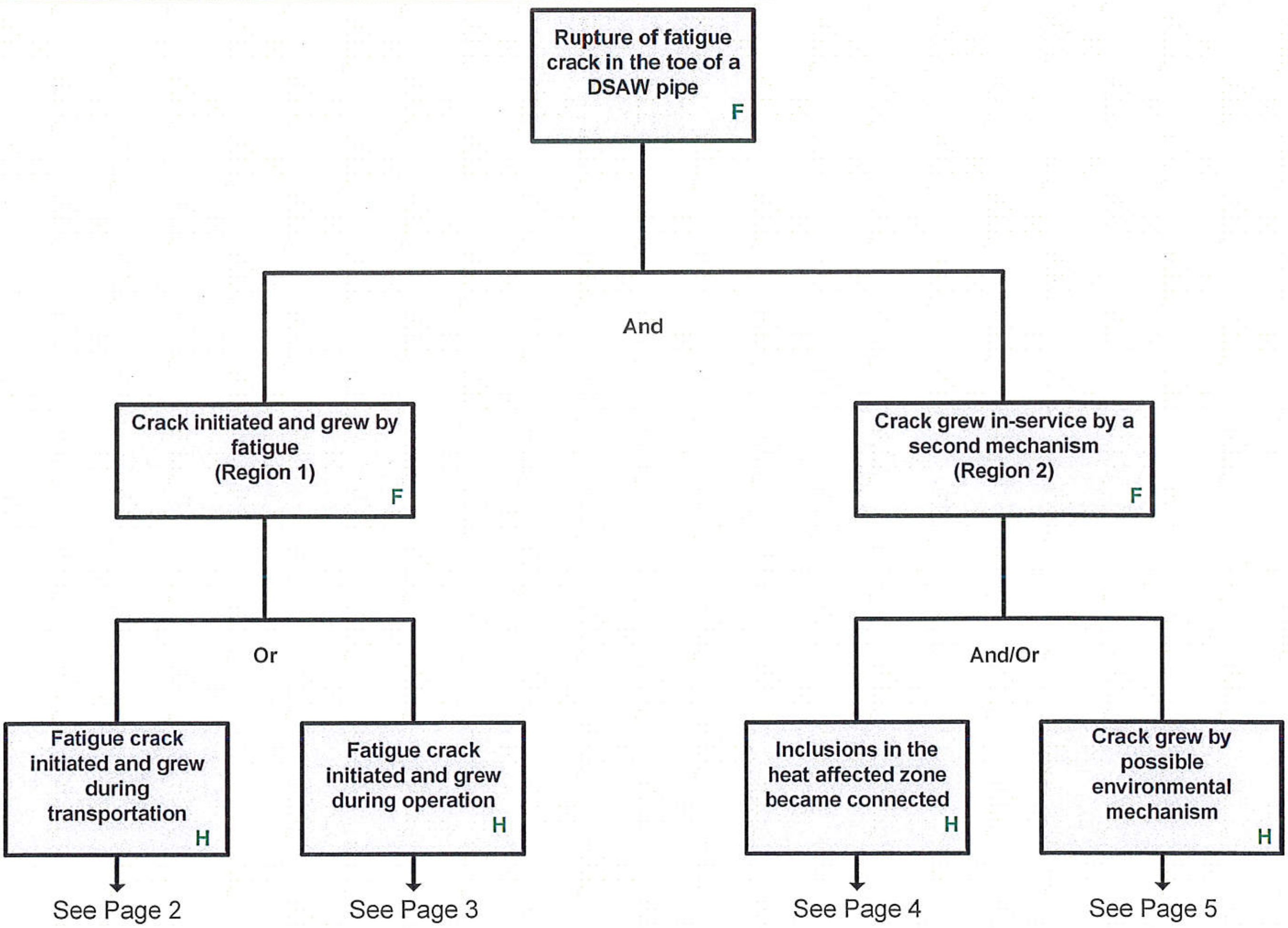
SUMMARY OF FAILURE ANALYSIS

- DNV GL in Columbus, OH performed the metallurgical failure analysis. The pipe section ruptured at a preexisting fatigue crack that initiated at the toe of the double submerged arc weld (DSAW) and exhibited three distinct regions:
  - Region 1 – a crack region at the internal surface with a maximum depth of 0.097 inches (37.3% of 0.260 inches nominal wall thickness) caused by fatigue;
  - Region 2 – a crack region with a stair-stepped appearance, beginning at the end of Region 1, resulting from higher stress intensity factor at the crack tip as the crack propagated deeper into the material and possibly an environmental component. The maximum depth of this region is 0.210 inches (80.8% of 0.260 inches nominal wall thickness);
  - Region 3 – the remaining ligament that overloaded during the rupture event.



DNV GL Mount M6

CAUSE AND EFFECT – HIGH LEVEL



REGION 1 – FATIGUE CRACK INITIATION AND GROWTH

- Transport Fatigue
  - Pipe was susceptible to transport fatigue
  - Pipe was transported multiple time
  - Pipe had a peaked geometry that acted as a stress riser
- In-Service Fatigue
  - Cracks initiated at corrosion micro-pits at the inner diameter surface of the pipe
  - Pipeline has aggressive pressure cycling
  - Pipe had a peaked geometry that acted as a stress riser

DNV GL concluded that "the fatigue crack initiation and propagation most likely occurred while in service. However, transit fatigue during transportation of the pipe cannot be ruled out as a contributing factor"

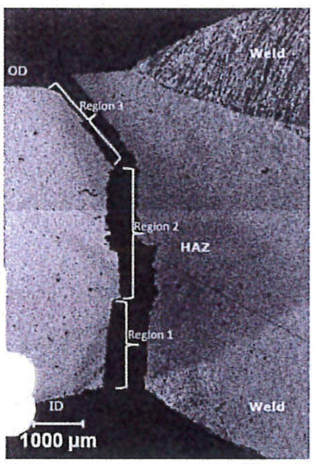
REGION 2 – CONTINUED CRACK GROWTH

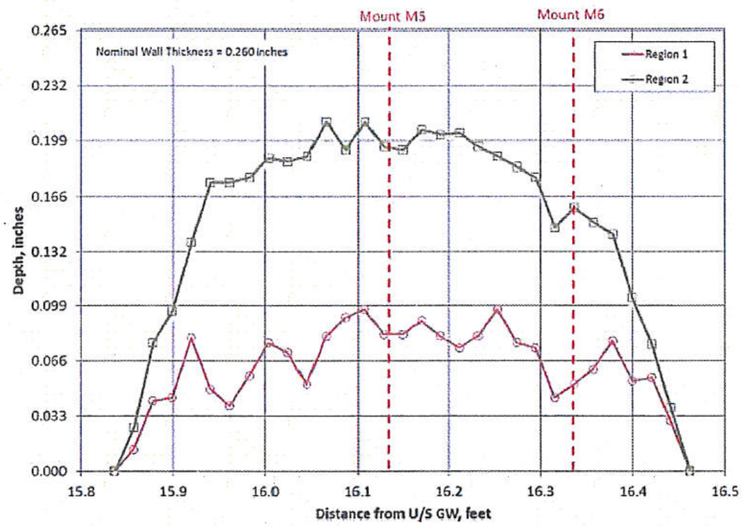
- A combination of three different factors contributed to changing how the crack grew in service and had a different appearance from Region 1

1. Linkage of inclusions through pressure cycling of the pipeline
2. Higher stress at crack tip
   - Higher stress intensity as crack penetrated deeper
   - Peaked geometry of the weld
3. Possible environmental mechanism

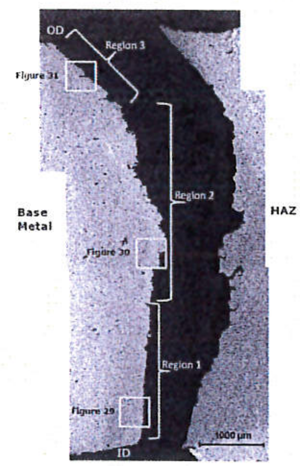
PRE-EXISTING FLAW PROFILE

DNV GL Mount M5





DNV GL Mount M6

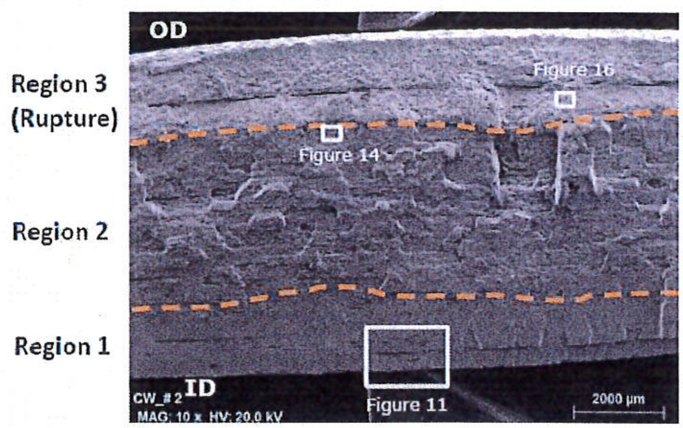


Length = 6.96 inches

Maximum depth of Region 1 = 0.097 inches (37.3% of nominal)

Maximum depth of Region 1 and 2 = 0.210 inches (80.8% of nominal)

Average wall thickness for Failed Joint = 0.275 inches



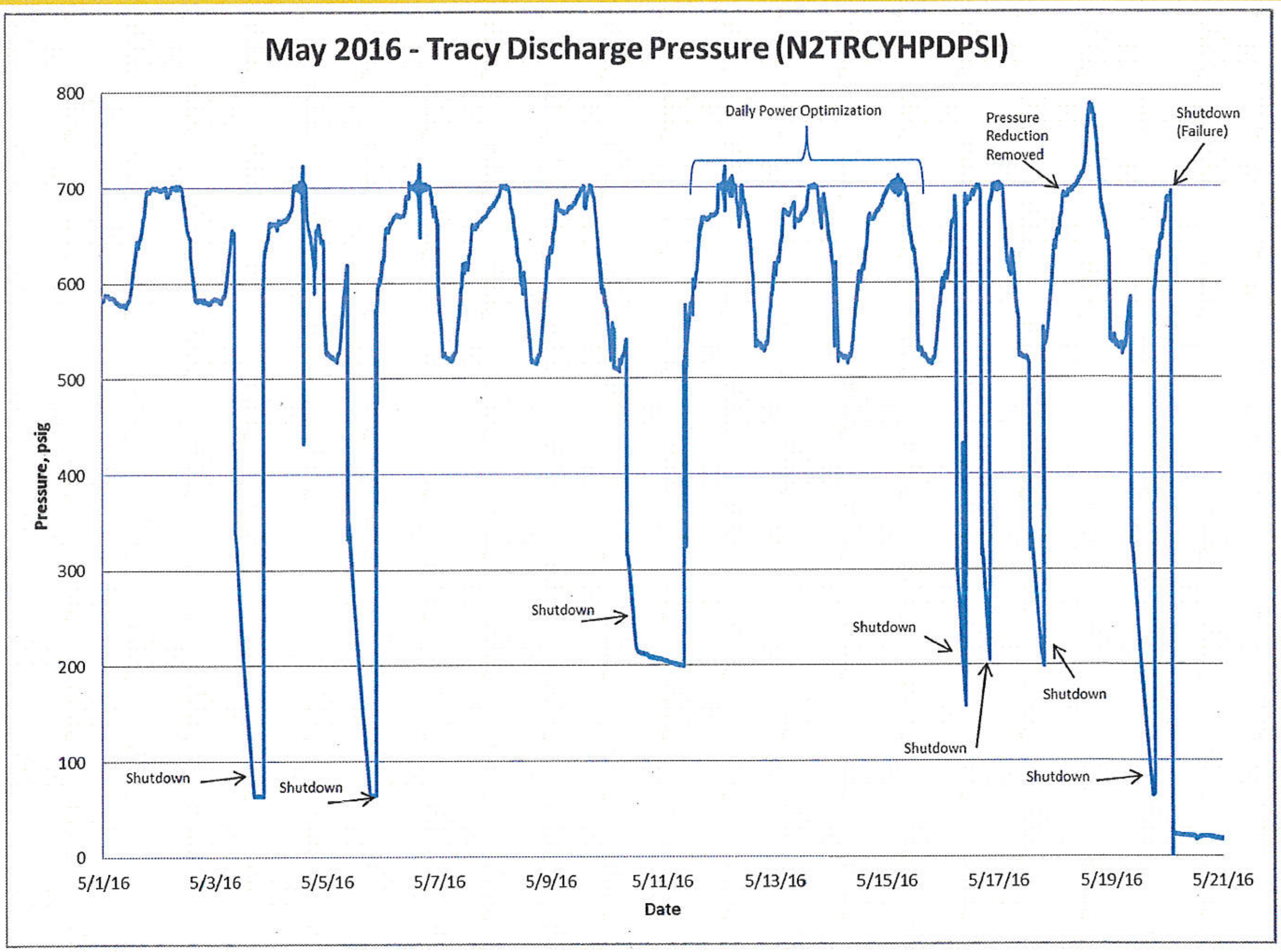
TRANSPORTATION FATIGUE

- Pipe with a diameter to wall thickness ratio greater that 50 is susceptible to transport fatigue per API 5L1
    - Failed joint had a ratio of 92.
- Pipe was transported multiple times
    - Transported from Armco (Houston, TX) to the Northeastern US
        - Likely the Delaware, Maryland, or Pennsylvania area (Columbia Gas)
        - Purchase records show API 5L1 Recommended Practices was followed
    - Transported from the Northeastern US to Coalinga, CA
        - Verbal information indicates that API 5L1 would have been specified per industry norms, written records have not been located
- Pipe had a peaked geometry that acted as a stress riser

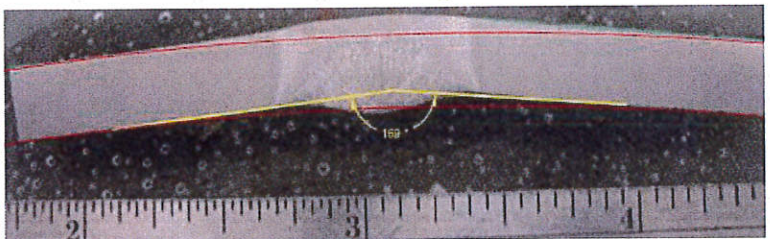
PIPELINE OPERATIONS – PRESSURE CYCLING

- Pressure cycling is a significant factor in the development and growth of fatigue cracks
- Pipeline had "aggressive" pressure cycles in accordance with Baker TT05 reference standard
  - Daily power optimization leads to pressure cycling
    - ~300 psig (23% SMYS) daily pressure change at original MOP of 936 psig (32% of MOP)
    - ~200 psig (15% SMYS) daily pressure change with 20% pressure reduction from 936 psig MOP (21% of MOP)
  - Shutdowns lead to pressure cycling
    - ~850 psig (65% SMYS) pressure change during shutdown at original MOP of 936 psig (91% of MOP)
    - ~650 psig (50% SMYS) pressure change during shutdown with 20% pressure reduction from 936 psig MOP (69% of MOP)

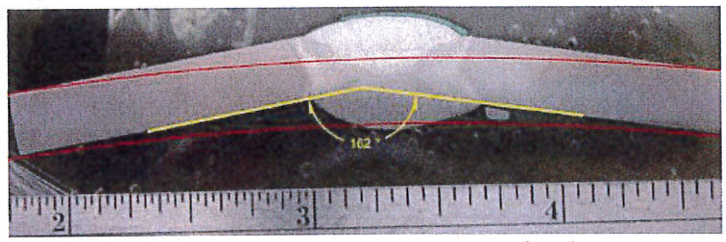
PIPELINE OPERATIONS – PRESSURE CYCLING (2)



PEAKED GEOMETRY



DNV GL Mount M7 - Unpeaked

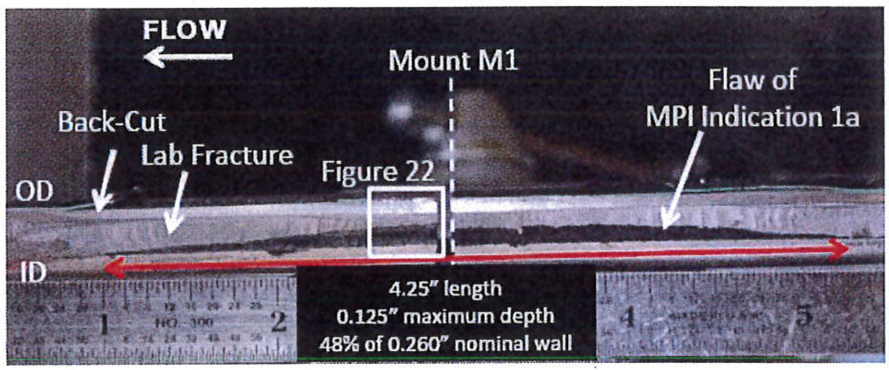


DNV GL Mount M1 - Peaked

- The "peaked" geometry of the DSAW was a causal factor for Region 1 and Region 2 for each hypothesis reviewed in the cause and effect diagram
- Quality control and quality assurance from the pipe mill should have identified the "peaked" geometry
- The "peaked" weld had a deformation of approximately 0.5% which is below the reporting threshold of traditional deformation ILI tools (1%)
    - The "peaked" seam would be considered a sharp contour and difficult to detect in larger diameter pipe using traditional geometry ILI surveys

ADDITIONAL FEATURE IN SAME PIPE JOINT AS FAILURE

- Three additional indications were identified through magnetic particle inspection
- MPI 1a exhibited similarities to the main feature with a Region 1 and Region 2
- Found to be 4.25 inches long and 0.125 inch (48%) deep
  - Was not reported by the ILI vendor in any report
  - Meets the stated detection threshold of UT-C survey
- MPI 1b and 2 were over-fill or under-fill respectively



DNV GL Mount M1

ILI VENDOR SELECTION

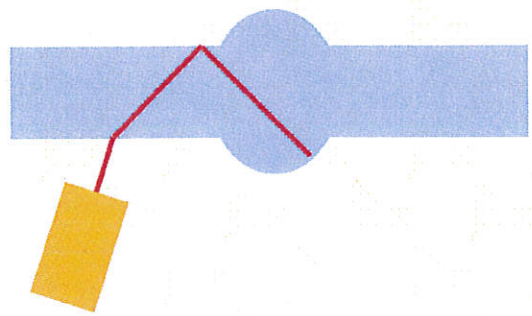
- A recommendation from the September 2015 LOPC RCA on Tracy to Windmill Farms was to perform a crack detection ILI survey
  - This recommendation applied to the three segments that have ARMCO pipe of similar vintage
- Rosen could perform both MFL-C and UT-C surveys
  - MFL-C can give a second opportunity to review the longitudinal seam weld for crack-like features

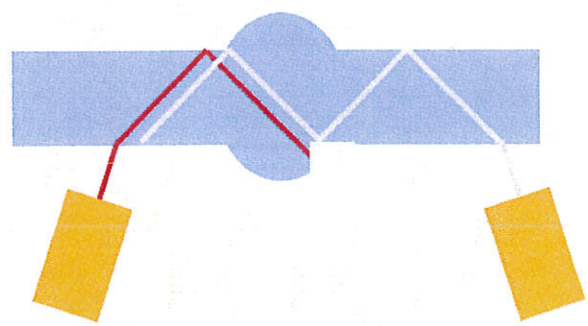
ILI VENDOR PERFORMANCE (1)

- Per Rosen, an "anomaly in joint 1250 was detected, identified, and boxed. It was classified as a crack-like in long seam" with the automated sizing process
  - Odometer 4073.718, 7.594 inch long and 0.150 inch (57.7%) deep
- Due to the volume of features that required review by the analysts, Rosen elected to modify their process for review of features. This included changing the amplitude that was used for signal review
  - No management of change or equivalent process was utilized within Rosen and SPLC was not consulted
- Per Rosen, "during sizing an incorrect amplitude was selected. Anomaly depth was calculated at < 0.08 inch"
  - Rosen believed that the reporting threshold was 0.08 inch
  - At Odometer 4073.718, per Rosen, "the Analyst overruled the [automated] call with the lower depth of 0.013 inch" (5%)
- No feature was reported at the location of the failure

ILI VENDOR SELECTION AND PERFORMANCE (2)

- Rosen has stated…
  - "The acoustics of DSAW long seams are complex. This is due to a parabolic reflection of the weld cap/crown"
  - "A strong signal is generated when the beam is reflected in itself"
  - "Mill grinding or repair cause a locally shifted self-reflection"
  - "Edge or root reflections occur, but are only visible from one side"





- Prior to the UT-C survey, SPLC provided a summary of the peaked geometry from the September LOPC to the Rosen sales representative. It is unclear if this information was shared with the technical staff within Rosen.

ROSEN JOINT 1250 SUMMARY

DATA EVALUATION ANOMALIES DETECTED IN JOINT 1250

ROSEN
empowered by technology

Manual Depth Sizing

Distance [feet]	Length [inch]	Angel [deg] [degree]	Type	MAX_AMPL [dB]	ABSDEPTH [inch]
4072.566	9.938	260.977	CRAC-LIKE	40.200	0.000
4073.718	7.594	261.033	CRAC-LIKE	42.800	0.013
4076.638	5.442	262.530	CRAC-LIKE	43.400	0.017
4081.677	3.245	261.556	CRAC-LIKE	45.200	0.032

Automated Depth Sizing

Distance [feet]	Length [inch]	Angel [deg] [degree]	Type	MAX_AMPL [dB]	ABSDEPTH [inch]
4073.718	7.594	261.033	CRAC-LIKE	51.000	0.150

The review of the data revealed a different depth for feature at 4073.718 ft based on the Automated Depth Sizing. The Analyst overruled the call with the lower depth of 0.013 in. This is typically done if the echo signal shows inconsistent pattern. This is subject for further investigation.

RECOMMENDATIONS (APPROVED)

#	Action	Due Date
	Integrity Management	
1	Enhancement of integrity program related to crack-like defects. Enhance process for identifying lines to survey, tool selection, vendor verification, run acceptance, and response. This item is procedural changes to be in place for 2017 crack detection surveys. This item will also serve to modify the seam susceptibility algorithm for of all seam types (e.g. DSAW, high frequency ERW, etc.)	12/15/16
2	Review pipelines with aggressive pressure cycling to determine: (1) if additional integrity assessment is required (i.e. ILI crack detection or hydrotest) and (2) if any operational modifications can be made to reduce the pressure cycle severity	12/15/16
3	Review previous ILI data in ARMCO pipe to determine if peaking can be identified in those surveys	12/15/16
4	Determine the reassessment interval for the ARMCO pipe in the SJV system for (1) ILI reassessment, and (2) hydrotest	12/15/16
	Product Quality Testing	
5	Confirm how frequently corrosiveness testing (CO2, H2S, pH, BS&W, etc.) in pipelines is performed	12/15/16
	Pipeline Operations	
6	End the practice of daily power optimization on SJV system	Complete
7	Install MOVs at Los Banos and Kamm to eliminate the necessity for shutdowns of adjacent segments when Los Banos and Kamm are shutdown	7/1/17
8	Review operating procedure related to planned shutdowns to identify opportunities to limit the magnitude or pressure cycling that occur on the North Heavy System	12/15/16
9	Develop a list of pipelines that are aggressively cycled and what is being done about the cycling. There needs to be corporate awareness for what pressure cycling does to the pipelines. This action needs to lead to more discipline and visibility of the issue	12/15/16
10	Continuously improve the process by ensuring there is documentation following a PL-1115 adjustment to set points that the notification is closed out by the technician following the implementation of changes	3/31/17