NATIONAL TRANSPORTATION SAFETY BOARD
OFFICE OF RAILROAD, PIPELINE, AND HAZARDOUS MATERIALS INVESTIGATIONS
WASHINGTON, D.C. 20594

Pipeline Operations Group Factual Report

Dredge *Waymon Boyd*

Propane Pipeline Strike Near the EPIC Dock, Corpus Christi Ship Channel
Corpus Christi, Texas

August 21, 2020, 0802 CDT

NTSB# DCA20FM026
(99 Pages)

June 30, 2021

Contents:

Accident Identification

Type:	Major Marine Casualty, Damages Exceeding $500,000
Date/Time:	August 21, 2020 at 0802 CDT
Location:	Corpus Christi Texas, EPIC Dock, Corpus Christi Ship Channel
Vessel:	Dredge *Waymon Boyd*, VIN: 261512
Carrier:	The Orion Group
NTSB No.:	DCA20FM026
Injuries:	6
Fatalities:	4

Pipeline Operations Investigative Group

Paul L. Stancil, CHMM
Sr. Hazardous Materials Accident Investigator
Pipeline Operations Group Chairman
National Transportation Safety Board
Washington, D.C. 20590

Roger Evans
Sr. Pipeline Accident Investigator (retired)
National Transportation Safety Board
Washington, D.C. 20590

Alvaro Rodriguez
Accident Investigator
Pipeline and Hazardous Materials Safety Administration
Accident Investigation Division
Oklahoma City, OK 73179

Ron Perez
Regional Lead Inspector
Railroad Commission of Texas
Corpus Christi, TX 78406

Lt. Lars Okmark
Investigating Officer
United States Coast Guard
Sector Corpus Christi
Corpus Christi, TX 78406

Nhan Truong
DOT Compliance Manager
Enterprise Products
Houston TX

Graham Kenyon
V.P. Risk Management
Orion Group Holdings, Inc.
Houston, TX 77034

1. Accident Summary

On Friday, August 21, 2020, about 0802 central daylight time, the US-flagged, non-propelled, 152-foot-long cutterhead suction dredge *Waymon Boyd* struck the submerged Enterprise Products 16-inch propane intrastate hazardous liquid transmission pipeline TX219 during dredging operations adjacent to the EPIC Marine Terminal, located on the Corpus Christi Ship Channel in Corpus Christi, Texas (Figure 1).[1] A geyser of propane and water erupted adjacent to the vessel. Shortly thereafter, the gas plume ignited, and fire consumed the vessel and surrounding shoreline. EPIC Marine Terminal security camera video, while not pointed directly at the accident location, captured a water geyser disturbance with a billowing white vapor cloud that moved west toward the dock facilities. About 1 minute, 6 seconds after the water geyser began, the video showed a flame front that moved from east to west, engulfing the dock facilities. A total of 18 personnel employed by Orion Marine Group were working or resting on the dredge and assist boats (tender boats, anchor barges, booster barges, and a supply barge) on the day of the accident. Four crewmembers died in the explosion and fire, and six were injured. Local first responders located the injured and transported them to local hospitals. They were eventually transferred to burn units in San Antonio, Texas, where one of the crewmembers later died from his injuries.

The vessel burned for 8 hours. The fire was extinguished at 1610. However, at 2030, fire aboard the dredge re-ignited, but was reported out by 2130. The dredge sunk overnight. The estimated release of propane from pipeline TX219 was 6,024 barrels.

Estimated property damages to the pipeline and lost commodity were about $2.09 million.

Figure 1. Accident scene, Corpus Christi Texas, August 21, 2020. USCG photograph.

[1] All times referenced in this report are Central Daylight Time.

2. Accident Location

The accident site on the Corpus Christi Ship Channel was located adjacent to the EPIC Marine Terminal, operated by EPIC Crude Terminal Company, L.P. (EPIC). The facility was located at 5802 Up River Road, Corpus Christi, Nueces County, Texas, formerly occupied by the International Grain Corporation grain export terminal (Figure 2). Enterprise Products pipeline TX219 was breached about 2 feet 8 inches east of girth weld no. 444000. The location of the breached pipe was Lat: [redacted] Long: [redacted].[2]

In June 2019, EPIC began to re-purpose the grain facility to enable it to export crude oil. EPIC modified the existing dock (known as the West Dock) for loading crude oil tank ships and has been operating a crude oil loading terminal at the facility since December 2019.[3] The facility supports the loading of Aframax tankers that are capable of transporting up to 750,000 barrels of crude oil. The dock is supplied by EPIC's 11-mile pipeline and is capable of loading tank ships at a maximum loading rate of 20,000 barrels per hour. The proposed East Dock would be capable of loading Suezmax-sized tank ships at a loading rate of 40,000 barrels per hour.[4]

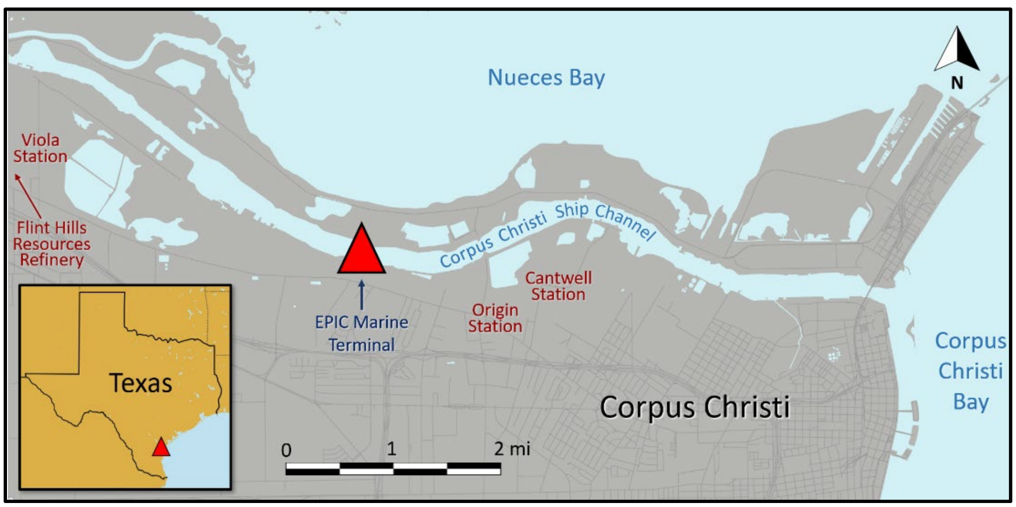

Figure 2. The accident and pipeline facilities locations. Background source: Google Maps.

[2] The accident location was determined by a September 24, 2020 SAM, Inc. survey of a buoy marker placed at the breached pipe location. The accident location was surveyed with a Trimble R10 GNSS receiver, verified against a control point to at least ±0.1-foot. Survey data was delivered in coordinated system NAD1983 ("Conus") State Plane Zone, Texas South 4205.

[3] https://www.businesswire.com/news/home/20191211005164/en/EPIC-Crude-Announces-First-Shipment-of-Crude-Oil-for-Export-From-the-EPIC-Dock-Facility-Located-in-Corpus-Christi-Texas (accessed December 4, 2020.

[4] Aframax tank ships can transport up to 750,000 barrels of crude oil, whereas Suezmax tank ships are capable of carrying up to 1,000,000 barrels.

3. Pipeline Operator, Enterprise Products

Enterprise Products Partners L.P. (Enterprise) is a publicly traded master limited partnership that was formed in 1998. Together with its consolidated subsidiaries, Enterprise is a North American provider of midstream energy services to producers and consumers of natural gas, natural gas liquids (NGL), crude oil, refined products, and petrochemicals. Enterprise conducts substantially all of its business operations through its consolidated subsidiaries. Among the services Enterprise offers are petrochemical and refined products transportation and storage, and a marine transportation business unit that operates primarily on inland and intracoastal waterway systems within the United States.[5]

Company assets include:

- 50,000 miles of pipeline,
- Storage for 260 million barrels of NGL, refined products, crude oil, and petrochemicals,
- 14 billion cubic feet of natural gas storage capacity,
- 22 natural gas processing plants,
- 24 NGL and propylene fractionators,
- Seven deep-water ship docks for loading multiple products within the Houston Ship Channel,
- Five deep-water ship docks for loading multiple products in Beaumont, Texas,
- Four deep-water ship docks for loading crude oil at Texas City and Freeport, Texas, and
- Two deep-water ship docks for loading ethane and ethylene at Morgan's Point, Texas.

Enterprise owns interests in NGL pipelines that transport mixed NGLs from natural gas processing plants, refineries, and marine terminals to downstream fractionation plants and storage facilities. In total, the Enterprise NGL pipeline systems total over 19,000 miles of their 50,000-mile pipeline inventory.

4. Dredge Operator, Orion Marine Group

Orion Marine Group (Orion Group) is headquartered in Houston, Texas. Orion Group maintains its Gulf Coast marine and industrial construction and commercial diving divisions in the Houston area. The company has been conducting dredging operations in coastal waterways for over 70 years and provides services for marine pipeline construction projects, including shallow water lay barge installation, repair, abandonment, and trenching.[6] The company owns and operates a fleet of more than 400 pieces of specialized equipment

[5] https://enterpriseproducts.com/operations/ngl-pipelines-services/ngl-pipelines
[6] Orion Marine Group company website: https://orionmarinegroup.com accessed August 23, 2020.

throughout their service regions, including heavy lift cranes, barges, hydraulic dredges and boosters, work boats, tugboats, dredges, and pile-driver hammers, and various support equipment and facilities. Figure 3 is a pre-accident photograph of the dredge *Waymon Boyd*.

Orion Group's fleet of mechanical and hydraulic dredges, includes:

- Three 24" cutter head suction dredges,
- Three 20" cutter head suction dredges,
- One 18" cutter head suction dredge,
- 20" to 24" hydraulic dredge boosters,
- Mechanical dredge rigs, and
- Mechanical and hydraulic offloading equipment.

Figure 3. Dredge Waymon Boyd, pre-accident photograph. Courtesy Orion Marine Group.

5. EPIC East Dock Dredging Project and Operations

5.1. Project Scope and Approvals

5.1.1 Dredging

During the project planning, on December 28, 2018, TMI Solutions, LLC provided EPIC a survey of existing utilities within the project area, including gas and hazardous liquid pipelines. The TMI survey included both the location of the pipelines and depth of cover as indicated in Figure 4. To maintain awareness of pipelines near the construction area, the EPIC facilities engineering manager insisted that the location of the Enterprise pipelines in and near the waterway be included in the project drawings.[7]

[7] NTSB interview of EPIC facilities engineering manager, December 1, 2020, p. 24.

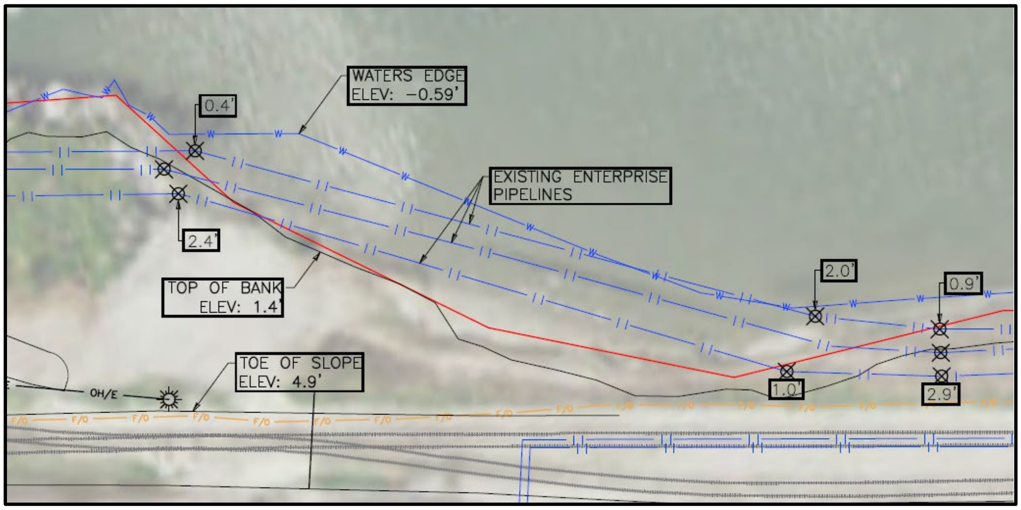

Figure 4. Excerpt of TMI Solutions LLC Survey of Existing Pipelines, EPIC POCCA Terminal, December 28, 2018. The numbered boxes indicate depth of cover on land. The blue water's edge line is Mean Lower Low Water.

On February 28, 2019, EPIC contracted Orion Construction L.P. (Orion Group) to perform the dredging work for its proposed East Dock facilities.

On May 3, 2019, Jacobs Engineering issued the original New EPIC Dock Slip dredging plans for construction of the East Dock facilities, including the site plan, dredge boundaries before soundings, and cross sections. The plans did not incorporate the 2018 TMI existing utilities survey information. The plans were appended to EPIC's May 3, 2019, application to the U.S. Army Corps of Engineers (USACE) for authorization to amend existing dredging permit SWG-2014-00559, issued in 2015, to Texas Fuel and Asphalt Company. The application sought permission to increase the dredged area from 7.09 acres to 8.64-acres and to remove 361,200 cubic yards of dredge material to a depth of -49 ft MLLW +1 ft over-depth. The amendment also included shifting the footprint of the project west by approximately 167 feet to accommodate larger vessels at the dock. The plan included the installation of a new pipeline rack that would run from the dock platform, along and over the existing Union Pacific Railroad tracks, and into the terminal.

Meanwhile, on March 20, 2019, USACE transferred existing dredging permit SWG-2014-00559 to EPIC Crude Oil. USACE issued the revised dredging permit on October 18, 2019.

The dredging project was implemented in two phases to accommodate an unrelated federal project for which the dredged material disposal area was required. The first phase of dredging operations began in May 2019 and involved dredging in the northern section of the project area, which encompassed less than half of the required dredging. The first phase of dredging was completed in mid-July 2019. [8]

Prior to initiation of the second dredging phase, Schneider Engineering, an affiliate of the Orion Group, replaced Jacobs Engineering as the project design company. Schneider Engineering imported the Jacobs Engineering plans into their own AutoCAD file, including the trapezoidal-shaped full-depth dredge boundary location points for the berth.[9] Schneider Engineering revised the dredge boundary dimensions in accordance with Houston Pilots or Corpus Christi Pilot's guidelines for proposed terminal setback distances, which are determined by the size of vessels intended to berth there.[10] The Schneider Engineering revised plan indicated the design depth for the berth was -46.5 ft., with an allowable over-depth of 1 ft. The berth design slope was 2.5:1 (horizontal:vertical) from its basin boundary shoreward. Dredging of the side slope was to follow as closely as practicable the lines indicated in the Schneider Engineering drawings. There was no allowable side slope over-depth in the dredge plan or engineering drawings. An excerpt of the Schneider Engineering June 23, 2020, revised dredge project plan overlaid on a Google Earth image with the location of pipeline TX219 determined in the TMI Solutions December 28, 2018, survey is shown in Figure 5.

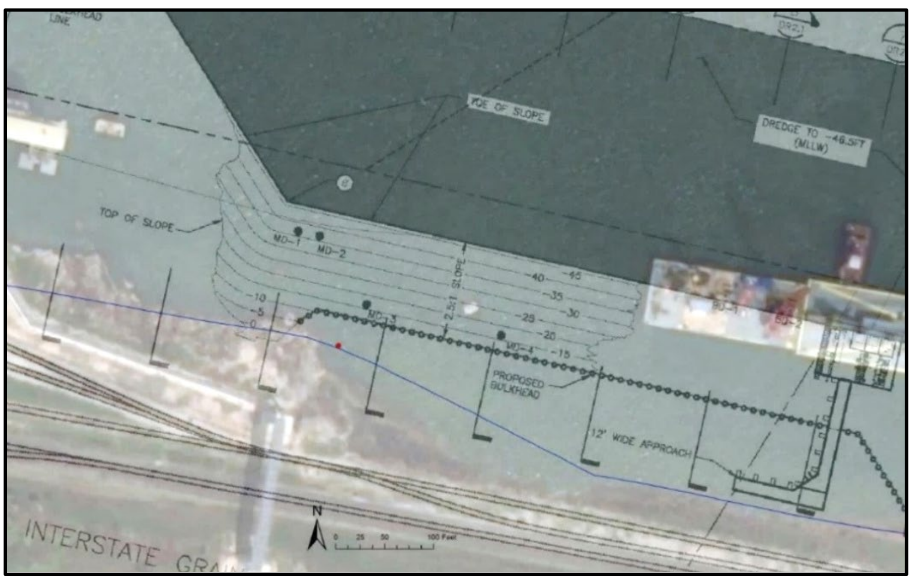

Figure 5. Excerpt of the June 23, 2020 Schneider Engineering revised dredging plan overlaid on Google Earth background, showing the TMI 2018 location of pipeline TX219 and the approximate accident location identified by a red dot.[11]

[8] EPIC facilities engineering manager, p. 18-19.

[9] NTSB interview of Schneider Engineering design engineer, October 29, 2020, p. 22.

[10] EPIC facilities engineering manager, p. 19, 63. On January 30, 2019, the Houston Pilots published updated Dock/Marine Project Guidelines to inform the design of dock projects to ensure the suitability of proposed docks for safely berthing and unberthing vessels of particular sizes.

[11] The approximate accident location depicted is based on the location of girth weld 444000 as determined during a 2016 inline inspection of the pipeline (see Sections 6.62 and 11.1). The pipeline location (blue line) was provided by Enterprise Products' KMZ file derived from the SAM, LLC pipeline survey of September 30, 2020.

As Schneider Engineering developed the dredge plan cross sections that it ultimately plotted on June 23, 2020, the supervisory engineer suggested that the design engineer produce a drawing showing the location of the pipelines to double-check whether the pipelines were situated outside of the dredge template. On June 22, 2020, using the plan depicted in Figure 6, the Schneider Engineering design engineer determined that Enterprise pipeline TX219 fell outside of the dredge template by about 8 to 10 feet at its closest point.[12] He further discussed the proximity of the pipelines during a follow up meeting with the supervisory engineer and vice president to ensure awareness of their presence and the need to adequately mark the pipelines.[13] However, the design engineer was not aware of the extent of pipeline location information provided to Schneider's client, the Orion Group.[14]

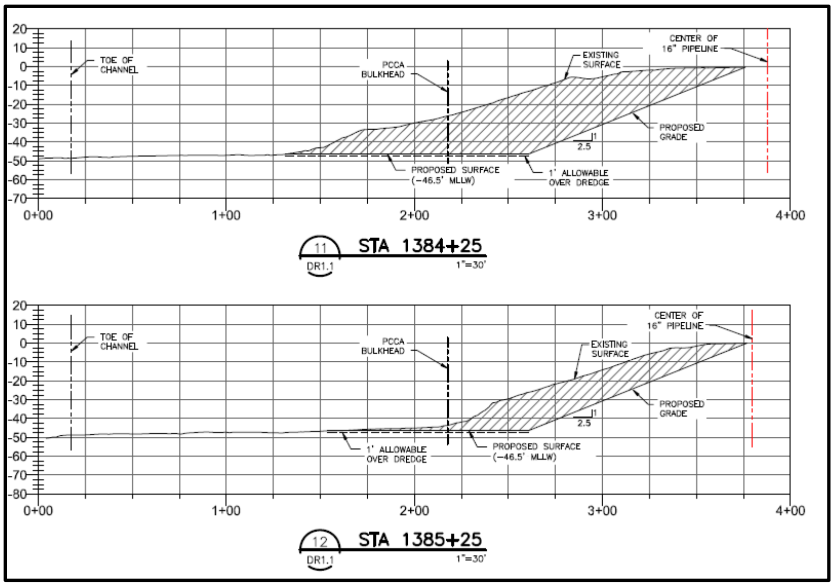

Figure 6. Excerpt of Schneider Engineering & Consultants EPIC Dock cross sections drawing prepared on August 24, 2020 from December 28, 2018 hydrographic survey data, indicating the closest proximity of Enterprise Products pipeline TX219 as determined by the design engineer and identified by a red line on the right side of each cross section. The hatched area denotes material to be dredged. The horizontal scale is shown in 25-foot increments. The design engineer reported that these drawings were the basis for his determination the pipeline clearance was 8 to 10 feet.

In addition to the above-mentioned approvals required of the dock and dredge plans from USACE and the Port of Corpus Christi Authority, the Texas Commission on Environmental Quality (TCEQ) is responsible for conducting Clean Water Act Section 401 certification reviews of Section 404 permit applications for the discharge of dredged or fill material into

[12] Schneider Engineering created a drawing after the accident on August 24, 2020 to show the pipeline location relative to the top of the slope as depicted in Figure 6.

[13] The design engineer stated that the date of the meeting is unknown, and no meeting minutes were recorded.

[14] Schneider Engineering design engineer, p. 33-34, 41-42.

waters of the United States, including wetlands.[15] TCEQ is the lead state agency that administers the Section 401 certification program in Texas, except with respect to oil and gas exploration.

The second phase of the project began after the Port of Corpus Christi Authority issued EPIC a July 17, 2020, notice to proceed for the placement of dredge material into Dredge Material Placement Area No. 1 and the Herbie A. Maurer Dredge Material Placement Area. The Port of Corpus Christi Authority also approved the Schneider Engineering dredging construction plans dated June 23, 2020. EPIC and the Orion Group had anticipated that the second phase of dredging would require about 75 days to complete, however EPIC requested the USACE allow for 100 days to account for unexpected delays.[16]

On July 29, 2020, the Orion Group towed the *Waymon Boyd* to the EPIC East Dock project site, and phase two of the dredging began that day.

5.1.2 Bulkhead and Pipeline Encroachment

In addition to the dredging, the EPIC Dock project included a proposed bulkhead along with 5 feet of sand backfill over the Enterprise pipelines that would be used as a dock platform to support the crude oil tank ship loading facility. The proposed bulkhead construction was to be performed under a different contract and managed by Orion Group's Deer Park, Texas construction office, which is a separate division of the Orion Group from the company's dredging assets.[17]

The Schneider Engineering design engineer told NTSB investigators that the project plans did not intend for existing soil to be excavated landward of the proposed bulkhead line since additional fill material needed to be trucked in to cover this area.[18]

On June 8, 2020, the EPIC right of way landman emailed the Enterprise senior manager, land encroachments, to request permission to add the cover material over their pipelines beginning the week of July 13, 2020. The EPIC right of way landman stated that contractors planned to use backhoes to spread and pack the sand backfill material. Attached to EPIC's encroachment request were construction plans and a KMZ file that depicted the location of the proposed bulkhead and backfill area (Figure 7).[19]

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[15] Section 401 of the Clean Water Act requires applicants for federal licenses or permits that may result in a discharge of pollutants into waters of the United States to obtain a certification from the state that the proposed discharge will comply with applicable water quality standards.

[16] EPIC facilities engineering manager, p. 21, 40.

[17] NTSB interview of the Orion Group Director, Health, Safety, and Environment, April 9, 2021.

[18] Schneider Engineering design engineer, p. 40.

[19] KMZ stands for Keyhole Markup Language Zipped. A KMZ file extension contains latitudinal and longitudinal coordinates and 3D model data used by Google Earth to display various features on a geographic platform.

In a July 13, 2020, email to the EPIC right of way landman, the Enterprise Products senior manager of land encroachments approved the EPIC request to add 5 feet of sand cover over the Enterprise pipelines. The senior manager of land encroachments requested that EPIC arrange for an Enterprise representative to be onsite at the time of construction and reminded EPIC that its contractor is required to place a One-Call notice prior to digging on or near the pipeline right of way.[20]

Construction on the proposed bulkhead and backfill project had not yet begun at the time the accident occurred on August 21, 2020.

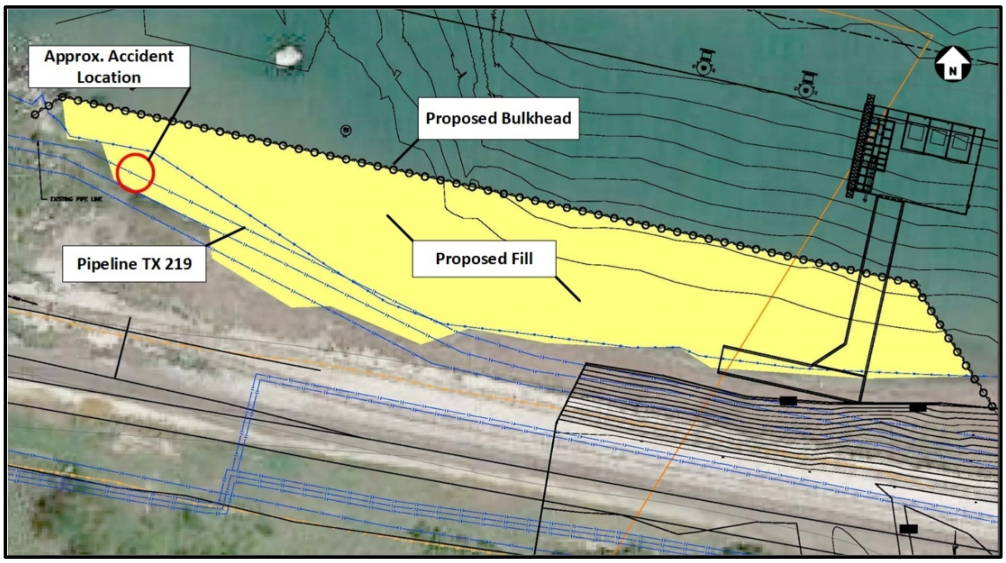

Figure 7. Annotated excerpt of Schneider Engineering & Consultants design and build plan for the EPIC East Dock, April 9, 2020, showing the proposed bulkhead, area to be filled, pipelines, and the approximate accident location. This drawing (without annotations) was included in the EPIC encroachment request to Enterprise Products on June 8, 2020.

5.2. Dredging Equipment Description

The dredge *Waymon Boyd*, VIN 261512, was a U.S. flagged non-propelled seagoing 151.7-foot, 290-gross-ton, steel hull cutter suction dredge that homeported in Port Lavaca, Texas. Formerly diesel-powered, the dredge had recently undergone retrofitting to run on electric power. The vessel was not authorized to carry hazardous cargo. The managing owner was Orion Marine Construction, Inc.

Hydraulic pipeline cutterhead suction dredges like the *Waymon Boyd*, are equipped with a rotating cutter apparatus surrounding the intake end of the suction pipe in order to dig and

[20] One-call systems are a central communications point comprised of member organizations that operate underground facilities in a specific geographic area. The system allows the public to make a single phone call or on-line request prior to digging to notify the affected utility operators with just one communication.

pump a large range of soil (i.e., sand and clay) and rock types. This dredge type has the capability of pumping dredged material long distances to upland disposal areas. The *Waymon Boyd* was equipped with a rotating cutterhead powered by 400 hp drive motor. The cutterhead had five blades on which were mounted 32 chisel teeth positioned forward of the suction head (see Figure 8). The cutterhead functioned to break soil cohesion such that a pumpable slurry of soil and water could enter the suction mouth behind the cutterhead.

Figure 8. Post-accident photograph of the dredge Waymon Boyd cutterhead, September 17, 2020, courtesy U.S. Coast Guard.

The *Waymon Boyd's* cutterhead was described as a type SC15, manufactured by VOSTA LMG B.V., Amsterdam, Netherlands. The type SC15 cutterhead had five blades that were marked "A" through "E" in the casting. Blades "B," "D," and "E" each contained rows of six teeth, while blades "A" and "C" contained rows of seven teeth.

Vosta LMG recommended using standard SC15.01 wide chisel teeth for dredging sand and clay. For harder soil like hard packed sand, Vosta LMG recommended using model SC15.02 narrower chisel teeth. For rock, the manufacturer recommended using SC15.03 pick point teeth. The *Waymon Boyd* cutterhead was equipped with the SC15.01 wide chisel teeth. Cutterhead teeth were fabricated from high alloy cast steel. Each tooth weighed 8.5 kg. A cutterhead tooth profile and dimensions are provided in (Figure 9).

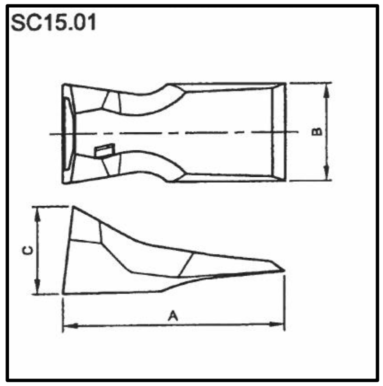

Figure 9. Vosta LMG type SC15.01 wide cutter tooth dimensions. A 278 mm, B 109 mm, C 118 mm.[21]

The *Waymon Boyd* cutterhead had been refurbished with new teeth at the beginning of the Epic Dock project. During dredging operations, crews inspected the cutterhead daily and replaced broken or missing teeth as necessary. The dredge crew inspected the cutterhead the day before the accident and found no missing or broken teeth.[22]

Electric motors rotated the cutter head and powered the suction pumps. According to the dredge captain, the leverman had to maintain the cutterhead depth below 10 feet and avoided running into large debris to prevent loss of suction and introduction of air into the dredge discharge pipeline. Loss of suction resulted in pump cavitation along with significant vibration, noise, and rapid drop in discharge line pressure. The process of repriming the dredge suction pumps involved removing air and debris from the discharge lines and could take as long as 6 hours to remedy.[23]

The *Waymon Boyd* suction/cutterhead was mounted to a structural device known as the ladder, which was used to extend and lower the cutterhead to the seabed (Figure 10). During normal operation, the dredge pivoted on one of two alternating spuds at its aft end, while the forward end cutterhead swung laterally along an arc as guided by anchors and wires. The leverman adjusted the ladder angle for the cutterhead with each pass for removing multiple layers of sediment from the seabed and slope until the desired dredging depth was achieved.

[21] Image and dimensions taken from Vosta LMG Maintenance Manual Vosta SC15 Cutterhead, 18-12-2003.

[22] NTSB interview of Orion Group dredge captain, January 6, 2021, p. 65- 67.

[23] Orion Group dredge captain, p.117-118, 135-136, and NTSB interview of Orion Group oiler, August 23, 2020, p. 42.

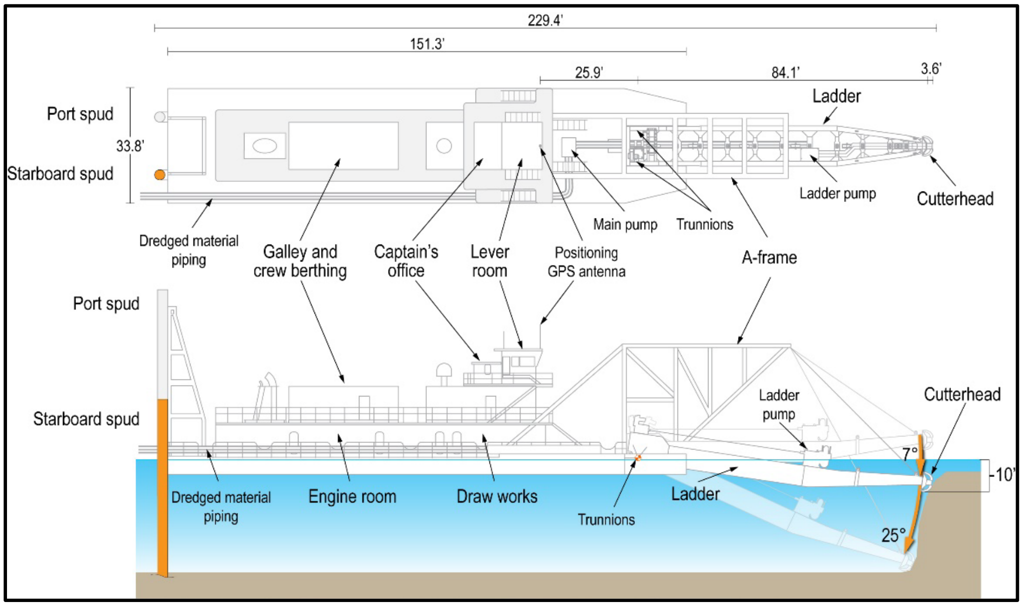

Figure 10. Drawing of the dredge Waymon Boyd showing dimensions and structural nomenclature.

For the EPIC Dock project, the dredged material was conveyed by centrifugal pumps and a floating and submerged pipeline about 3.5 miles to the Port of Corpus Christi Authority dredge material placement area DMPA No. 1 or the adjacent Herbie A. Maurer DMPA.[24] Two booster barges equipped with supplemental pumps facilitated moving the dredged material long distances to the DMPAs. Other support vessels involved in the project included two crane-equipped 60-foot anchor barges (BA-A-0014 and BA-A-0019) that tended swing anchors to either side of the dredge. Cables between the anchors and the ladder were used to guide the front of the dredge and cutterhead along an arc. Also used on the work site were deck barges BD-B-0002 and BD-A-0026 (128 foot and 120 foot), and fuel barge (32 foot) TD-B-0016. At the time of the accident, the *Waymon Boyd* and the two anchor barges were the only vessels near the breached pipeline that sustained fire damage.

5.3. EPIC East Dock Dredging Operations

The Orion Group survey department received the Schneider Engineering EPIC Dock construction plans and was responsible for developing the dredge template plans along with pre-dredge hydrographic survey data of the dredge area for integration into DREDGEPACK®. The Orion survey superintendent and a two-person survey crew also conducted weekly hydrographic surveys to determine the dredging production rate and volume of material remaining to be removed. The surveyor used this survey data to update the *Waymon Boyd's*

[24] DMPA No. 1 and the Herbie A. Maurer DMPA are located between the mouth of Nueces Bay and the Corpus Christi Ship Channel.

DREDGEPACK® software and was the sole individual responsible for uploading dredge template data into the software.[25]

Beginning on July 29, 2020, the *Waymon Boyd* continued phase two dredging operations with two 12-hour shifts, 24 hours a day. The crew worked on rotations of 14 days on and 7 days off. Work progressed generally from east to west, beginning in the deep channel and progressing toward shore.

The dredge crew only relied on data contained in the DREDGEPACK® software to enable them to monitor and track dredging operations and the position and depth of the cutterhead in real time. During dredging operations, crews did not refer to other drawings or plans when determining where to position the cutterhead. The location of the Enterprise pipelines, which Orion determined were located outside of the dredge template, were not displayed on the DREDGEPACK® screen.[26]

During the couple of days prior to the accident, the *Waymon Boyd* cutterhead dug into an inordinate amount of concrete rubble or rocks along the southern slope of the dredge template leading toward shore. The debris fouled the main pump and resulted in downtime to clear and reprime the pumps. Referring to the Schneider Engineering EPIC Dock construction plan (see Figure 14), the general location where this rubble or rock was encountered was an old mooring located above the words "Interstate Grain" printed on the plan.[27]

During the week of August 16, 2020, a tank ship was moored at the EPIC West Dock taking on crude oil cargo. Until the ship departed on Wednesday, August 19, dredging operations had been restricted to the east side of the dredge template. On the evening of August 19, the *Waymon Boyd* was repositioned to the west side of the dredge template in the area of two mooring dolphins to resume dredging in that area.

About 1730 on August 20, a rubber coupling on the shaft that drove the cutterhead broke after the dredge contacted large concrete debris, bringing operations to a halt. The night shift crew and the dredge captain worked on repairing the cutterhead drive shaft until about midnight. Dredging recommenced once the repair was completed.[28]

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[25] DREDGEPACK® is a proprietary software used for controlling cutter suction, hopper, bucket, and excavator operations. Survey data is loaded into a color-coded matrix and the system monitors the exact position and depth of the digging tool to keep track of the dredged surface. Further information about the system is provided at https://www.hypack.com/dredgepack

[26] NTSB interview of Orion Group deck captain, December 2, 2020, p. 49.

[27] Orion Group deck captain, p. 20, 22.

[28] NTSB interview of Orion Group dredge captain, January 6, 2021, p. 30-32.

Following a shift change at 05:30 on the morning of the accident, the day crew assembled for a safety meeting in the leverman station on the top level of the dredge. Safety meetings were typically held for 20 to 30 minutes at the beginning of each shift and included a discussion of one or two safety topics, as well as the assignment of work tasks for the day. Normally, the safety meeting would be led by the dredge captain or deck captain; however, the captain was not present at the meeting on August 21 because he had been up late the night before overseeing the repairs. When the dredge captain and deck captain were not present, the leverman led the meeting. However, the leverman did not stop operating the dredge during the safety meeting.[29] None of the crew members interviewed recalled any discussion about working near the pipeline during the August 21 safety meeting preceding the accident.

5.4. Dredging Company Personnel Involved in the Accident

At the time of the accident, 18 Orion Group personnel were involved in dredging operations on the *Waymon Boyd* and support vessels or were off duty and stationed on board the dredge. Crewmembers included:

- The dredge captain, who was overall in charge of directing and coordinating dredging operations. The dredge captain was also responsible for working with the deck captain and other crew members to ensure that the dredge work was progressing consistent with the projected time schedule and that all operations were being performed in a safe and efficient manner.
- The chief engineer, who was responsible for operation of the engines, motors, and equipment aboard the dredge.
- The day and night shift levermen, who used operating levers and controls to position the dredge and cutterhead during dredging activities.
- Five deck hands, who performed a variety of duties related to operation of the dredge.
- Two second engineers, who operated, maintained, and performed maintenance on engines, motors, and equipment aboard the dredge and various support vessels and barges.
- Two mates, who supervised deck hands and performed assigned deck duties as required.
- Two oilers, who were responsible for equipment checks and greasing engines, motors, and machinery.
- One welder, who repaired various machinery.
- One dredge tender operator, who among other tasks, loaded and unloaded materials from vessels and barges, docks, and trucks.
- One cook, who prepared meals for the crew and was responsible for housekeeping.

[29] NTSB interview of Orion Group mate, August 31, 2020, p. 15, 20.

The four crew members killed in this accident included the night shift leverman, the chief engineer, a second engineer, and the cook. One deckhand was transported from the scene to the hospital for emergency care and died 68 days later.[30]

Additional Orion Group personnel involved in the project included the deck captain and two dredge superintendents, who were not aboard the *Waymon Boyd* at the time of the accident. The deck captain assisted in day-to-day operation of the dredge and performed the duties of the dredge captain when this person was absent. The superintendents shared responsibilities for directing and coordinating all day-to-day operations with the dredge captain or the deck captain. The superintendents visited the dredge on average about once or twice per week. Their primary method of communication with the dredge was through review of daily reports by email or by telephone conversations.[31]

Orion survey department personnel were not working on scene at the time of the accident. Their most recent weekly hydrographic survey before the accident occurred was conducted on August 17, 2020.[32]

The Orion Group project engineer visited the job site about once or twice a week and was not on scene the day of the accident. At the beginning of the project, the project engineer was responsible for filing One-Call notifications and transmitting One-Call response data to the Orion management team. The project engineer also prepared dredge production summaries developed from the leverman's logs and lost time reports.[33]

The project engineer reported to the Orion Group project manager, who was involved in project estimating and establishing the dredging contract with the client, EPIC. Afterward, he turned the project over to Orion's field operations division for executing the job but maintained relations with EPIC concerning progress reports and pay estimates.[34]

6. <u>Pipeline Description and Operations</u>

6.1. General Description and History

Hazardous liquid transmission pipeline TX219 was owned by South Texas NGL Pipelines, LLC and operated by Enterprise Products Operating LLC, both of which are subsidiaries of Enterprise Products Partners L.P. Enterprise acquired the affected pipeline TX219 from the

[30] The NTSB defines fatal injury as an injury that results in death within 30 days of the accident.
[31] NTSB interview of the Orion Group dredge superintendent 1, September 30, 2020. p. 10-11.
[32] NTSB interview of the Orion Group surveyor, September 30, 2020, p. 17-20.
[33] NTSB interview of the Orion Group project engineer, September 11, 2020, p. 10-11.
[34] NTSB interview of the Orion Group project manager, September 11, 2020, p. 7-8.

Exxon Corporation in 2005. The pipeline connected the Flint Hills Resources Corpus Christi, LLC refinery to propane storage at the Enterprise Origin Station.

The breached pipe was part of a 9,151-foot pipeline segment that was fabricated from 16-inch outside diameter, 0.219-inch wall thickness API-5L, X-46 grade steel pipe with a specified minimum yield strength (SMYS) of 46,000 psi. The pipe seam was electric resistance welded (ERW), of unknown frequency.[35] In the vicinity of the accident the pipe was coated with coal tar, over which was a 2-inch-thick concrete coating.[36] The maximum operating pressure at the accident location was 787 psig. The pipeline was constructed in 1968, however, the pipe manufacturer and the date of manufacture are unknown. The pipeline segment was protected from corrosion by an impressed current cathodic protection system. At the time of the accident, the pipeline was used to transport non-odorized liquefied propane.

The Flint Hills Resources refinery produced and stored propane within its facility for introduction into pipeline TX219 as needed. Propane entered Enterprise's pipeline facilities at the Viola Meter Station and flowed in an easterly direction 5.024 miles to a pipeline interconnect at Enterprise's Cantwell station. At the Cantwell station, Line TX219 was connected to Line M4-6, a 6-inch diameter, 0.47-mile pipeline that ran from the Cantwell station to storage at the Enterprise Origin station (Figure 11). The length of the pipeline segment between isolation valves was 29,040 feet.

The Flint Hills Resources refinery supplied propane to pipeline TX219 in batch deliveries, meaning that the pipeline did not run continuously. Generally, two to three propane batches per day were transported on the pipeline. The pipeline was not flowing when not actively transporting product from the refinery. During the month prior to the accident, Enterprise Products received 75 batches of propane in volumes ranging from about 251 barrels to 1,637 barrels.

[35] Enterprise Products assumes that its pipe segments constructed prior to 1970 have low-frequency ERW pipe seams. Metallurgical analysis would be required to distinguish between high-frequency and low-frequency ERW seams.

[36] The extent of the concrete sleeving beyond the accident location is unknown.

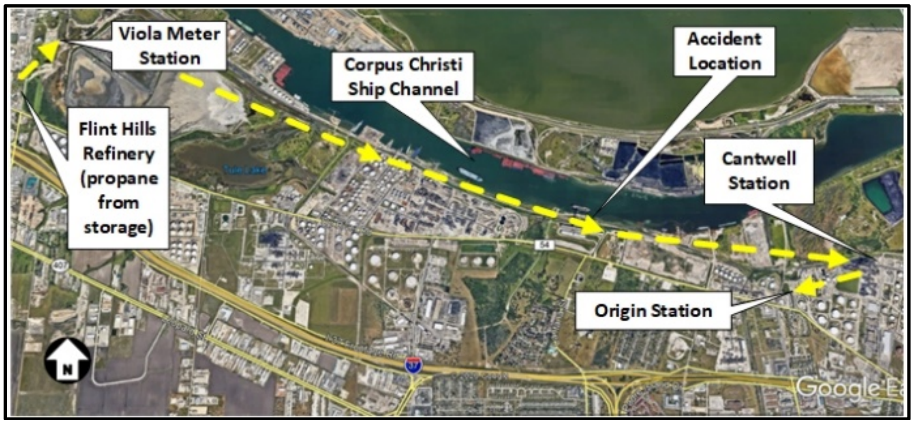

Figure 11. General flow path for Enterprise Products Pipeline TX219. Background image source: Google Earth.

Pipeline TX219 is an integral part of the Enterprise Products South Texas/Eagle Ford Region operations area at Origin Station, where a 24-person support operation is led by the manager of operations. The organization consists of two pipeline supervisors and an administrative assistant who report to the manager of operations. One pipeline supervisor manages five pipeline operators, three pipeline technicians, and a laboratory assistant. The other pipeline supervisor manages one mechanical technician, five pipeline technicians that focus on hazardous liquid pipelines, and five pipeline technicians that address gas pipelines.

Enterprise Products classified pipeline TX219 as an onshore pipeline, which generally ran parallel to the shoreline of the Corpus Christi Ship Channel in the vicinity of the accident. The Enterprise Products annual report to the Pipeline and Hazardous Materials Safety Administration (PHMSA) for calendar year 2019 hazardous liquid and carbon dioxide pipeline systems indicates that all of its hazardous liquid pipelines in the State of Texas were classified as onshore pipelines.[37]

On August 29, 2018, Enterprise Products revised its determinations of High Consequence Areas (HCA) for pipeline TX219 as defined in 49 CFR 195.452. This determination identified the following HCA boundary types that affected the entire 5.024-mile pipeline segment:

- Commercially navigable waterway (aerial dispersion),[38]
- Other populated area (aerial dispersion),[39]

[37] While federal regulations do not define onshore pipelines, 49 CFR 195.2 defines offshore as beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters..

[38] A commercially navigable waterway, as defined by 49 CFR 195.450, is a waterway were a substantial likelihood of commercial navigation exists.

[39] According to 49 CFR 195.450, other populated area means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

- Ecological unusually sensitive area (aerial dispersion),[40] and
- Highly populated area (direct).[41]

Based upon Enterprise Products' records review for Line TX219, there was no known history of previous accidents, as defined by 49 CFR 195.50. Additionally, an Enterprise Products integrity engineer reported in an October 19, 2018 pipeline integrity information analysis that from 2011 until the date of the accident, pipeline TX219 had no history of unintentional in-service releases or near-miss incidents.

6.2. Pipeline Cover

The Texas General Land Office (TGLO) is tasked with overseeing erosion control, mitigation, and coastal preservation projects in the State of Texas. TGLO reported that the average erosion rate for the 367 miles of Texas coast is 4.1 feet per year. The TGLO states that 64 percent of the Texas coast is eroding at an average rate of about 6 feet per year, with some locations losing more than 30 feet per year.[42]

The breached segment of pipe had become situated within the waterway from years of progressive land loss near the EPIC Dock project area (Figure 12). The length of the pipeline TX219 segment traversing the waterway at the accident location was about 265 feet.[43]

On December 28, 2018, the TMI Solutions LLC depth of cover survey found the pipeline had 0.4 feet of cover on the west end of the water exposure at the point where the pipeline transitioned back onto land nearest the accident location. The pipeline had 2.0 feet of cover at the east end of the waterborne segment (see Figure 4, Section 5.1.1 of this report).

During a pre-accident site visit on July 16, 2020, the Enterprise Products hazardous liquid pipeline technician observed that all but about 15 to 20 feet of the pipeline segment on the west side of the gap between the shorelines (nearest the breach location) was visibly exposed at the time of his visit a few inches to a foot below the water surface. He observed the 15-to-20-foot western-most portion of the pipe was covered by a sandbar.[44]

[40] Title 49 CFR 195.6 defines an unusually sensitive area as a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

[41] Title 49 CFR 195.450 defines a high population area as an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.

[42] https://www.glo.texas.gov/coast/coastal-management/coastal-erosion/index.html (accessed March 10, 2021).

[43] As determined by Google Earth measurement tools, imagery date January 31, 2020.

[44] NTSB interview of Enterprise Products hazardous liquid pipeline technician, September 16, 2020, p.24-25, 36.

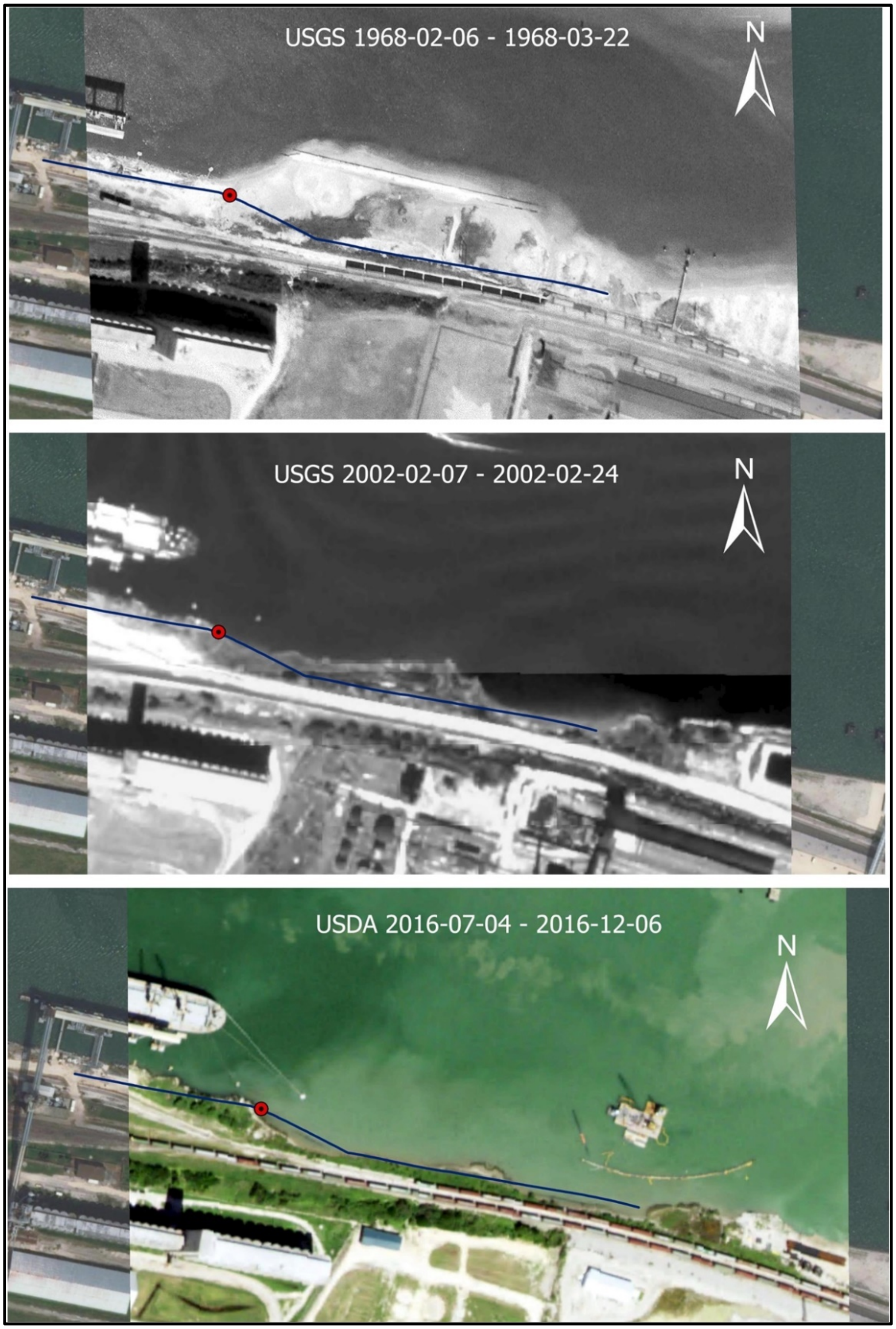

Figure 12, EPIC East Dock project area, 1968 (year the pipeline was installed), 2002, and 2016, showing the extent of land loss since its construction. USDA and USGS photographs overlaid on Google Earth image. The blue line indicates the location of pipeline TX219 (TMI Solutions, 2018) and the approximate accident location is indicated by the red circle.

The Enterprise gas pipeline technician could see the pipeline for most if its length between the shorelines, except for about 60 feet of the west side that was covered with sand.[45]

In its January 12, 2021, correspondence with NTSB investigators, Enterprise stated that Line TX219 was not exposed in the waterway. According to Enterprise, the prominently visible pipeline near the accident site was an abandoned 10-inch pipeline that runs parallel to Line TX219. A post-accident depth of cover survey that Enterprise contractor SAM conducted on October 1, 2020, showed the waterborne segment of the pipeline was covered with soil, except for the area immediately around the breaching damage. According to the survey, the depth of cover measurements taken at intervals of about 10 feet along the waterborne segment ranged from 0.1 feet to 1.5 feet. The survey found no cover over the pipe at the accident location.

NTSB investigators noted an additional 370-foot underwater segment of pipeline TX219, beginning about 500 feet east of the underwater segment adjacent to the EPIC East Dock site. Although two exposed parallel pipelines are visible in 2020 Google Earth imagery, this area was outside the limits of the TMI Solutions 2018 utilities survey and the October 1, 2020, SAM, Inc. depth of cover survey. In total, approximately 750 feet of Line TX219 was located near the shore or within the Corpus Christi Harbor waterway.

Enterprise Products told NTSB investigators that it manages exposed pipeline segments on a case-by-case basis, using criteria that includes, but is not limited to:

- Land use (commercial, residential, agricultural),
- Pipeline operating status (active vs. idled),
- Type of crossing (e.g., canal, creek, or river),
- Historical maintenance history,
- Pipeline integrity history,
- Corrosion prevention history, and
- Circumstances causing the exposure.

6.3. Pipeline Control

Because Flint Hills Resources refinery owns and operates the pump that moves the propane through the pipeline system, it was therefore necessary for the Enterprise Pipeline Control group to coordinate delivery of the propane batches with the refinery. Flint Hills Resources typically notified Enterprise of the propane volume contained in their tank set, which constituted the total volume of the batch to be transferred.[46] For determining flow rate and

[45] NTSB interview of Enterprise Products gas pipeline technician, September 16, 2020, p. 47.
[46] NTSB Interview of Enterprise Products Pipeline Controller, October 22, 2020, p. 62.

duration, the pipeline controller considered factors such as product schedule, current terminal tank storage capacity, and loading and delivery demands.[47]

6.3.1. Pipeline Control Center

The Enterprise pipeline control center is located in Houston, Texas, where a pipeline controller monitors and controls the movement of propane in pipeline TX219 over a supervisory control and data acquisition (SCADA) system. The pipeline controllers are responsible for simultaneously operating between five and ten pipelines. An example of a pipeline controller's schedule is generally to work 12-hour shifts with 4 days on and 3 days off. The SCADA system allows the pipeline controller to monitor pipe pressures and product flow rate from one point to another along the system. The system also provides the pipeline operator the capability of manipulating certain remotely controlled pipeline valves.

The SCADA system monitored the flow rate from the Viola Meter Station to Origin Station, the incoming pressure and outlet surge relief skid pressure at Viola Meter Station, the Viola Meter Station to Origin Station pressure, and the Viola Meter Station control valve position.[48] The SCADA system also provided the pipeline controller the ability to monitor pressure and flow on pipeline M4-6. The pipeline operator also had the ability to remotely control closure of motor-operated valve MOV-20 and emergency shut down valve SDV-25, which were located at the Viola Meter Station. When either of these valves closed, the entire feed to TX219 was isolated (Figure 13). In the event anomalous conditions required further investigation, the pipeline controller relied on field pipeline resources such as pipeline operators and pipeline technicians to conduct field checks and to make movements on manually operated pipeline valves when needed.

[47] Enterprise Products Pipeline Controller, p. 13.

[48] Surge relief skid systems provide protection to the pipeline from dangerous pressure spikes caused by changes in liquid flow rate.

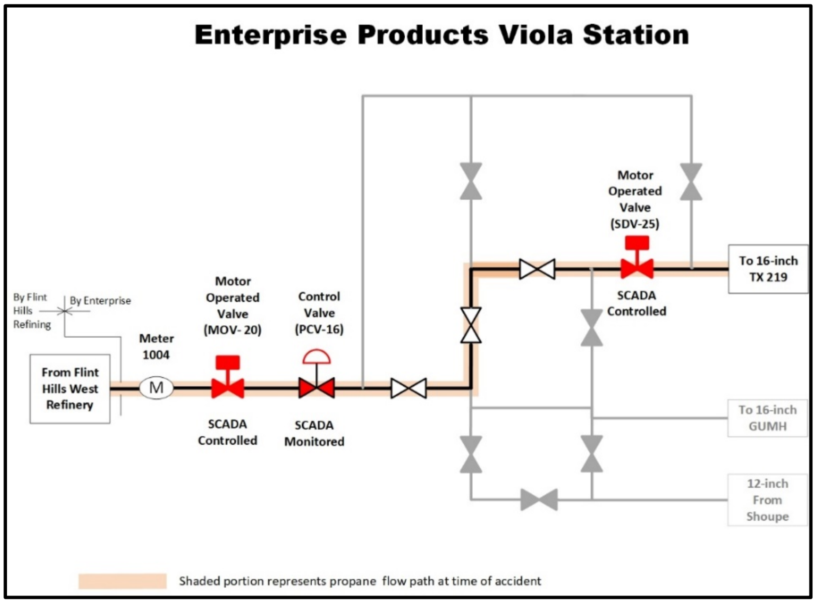

Figure 13. Viola Meter Station pipe and valve simplified diagram for pipeline TX219.

The pipeline controller's SCADA screen provided color-coded alarms (yellow, magenta, red) coupled with audible alarms for such circumstances as over pressure and under pressure conditions. A yellow pipeline monitor alarm condition typically occurred when there was some sort of anomaly that required the operator's attention or follow up investigation by a pipeline technician. Yellow alarms may not necessarily have signaled an emergency condition and could sometimes have been triggered by metering anomalies. An example of a magenta alarm would be an over-pressure indication on the pipeline. However, a red pipeline monitor alarm was considered critical and required dispatching a pipeline technician to further investigate. Red alarms could signal a leak but may also have been triggered by such things as a customer shutting down flow to a pipeline while line pressure was attempting to achieve a static state.[49] In the case of pipeline TX219, the SCADA low pressure alarm set point was 156 psig.

6.3.2. Control Valve Operation

The control valve (PCV-16) was located downstream of the flow meter (Meter 1004) and had two setpoints relating to pressure and to flow rate. Enterprise told NTSB investigators that the control valve was set to close at 200 psig to maintain pressure in the meter to a minimum of 200 psig. The purpose of this set point was to ensure that the propane flowing through the meter remains in a liquid phase for accurate measurement purposes. If the meter detected pressure below 200 psig, the control valve would close to 100 percent. Additionally, the control valve would close to throttle the flow to ensure it did not exceed 420 bph for flow measurement

[49] Enterprise Products pipeline controller, p. 16, 39 – 40.

accuracy purposes. The pump at Flint Hills Resources did not discharge at a rate or pressure to Viola Station that would have necessitated overpressure protection systems for Line TX219.

When the meter sensed pressures above 200 psig and flow below 420 bph, the control valve opened. When the line pressure or flow neared the 200 psig or 420 bph thresholds, the control valve would start to close and control the product movement to ensure the meter could accurately measure the throughput. Only one of the two setpoints needed to be met for the valve to close 100 percent.

Enterprise told NTSB investigators that at 0805 on the day of the accident, the control valve's pressure setpoint was tripped when the pipeline pressure fell below 200 psig, so the valve closed and remained closed.

6.4. Leak Detection

In addition to low pressure alarms generated by the SCADA system, Line TX219 was equipped with Pipeline Monitor (PLM), which is a type of computational pipeline monitoring (CPM) leak detection system, that uses compensated volume balancing (CVB).[50] This type of system computes and compares the operational changes in line pack volumes with the volume metered into a pipeline and the volume metered out of a pipeline system for predefined time periods.[51] This can be expressed as:

$$\text{PLM Deviation} = \text{Meter Out} - \text{Meter In} + \Delta\ \text{Line Pack}$$

The standard unit of the PLM Deviation is in barrels. The PLM Deviation was calculated at one-minute intervals and it was an accumulated sum of the one-minute deviations for a rolling time period. The rolling periods were set at 60-minutes and 24-hours to minimize false alarms due to pipeline transients. The alarm limits were set to alert the pipeline controller if a PLM Deviation was detected that exceeded normal flow and pressure thresholds for the rolling time period. The time it takes for the system to detect a leak depended on the size of the leak; the smaller the leak the more time it would take to be detected by the system.

Until this accident, Enterprise had recorded no history of abnormal operating conditions associated with leak detection, such as pressure/flow variations or unexplained line

[50] Computational pipeline monitoring (CPM) is a software-based monitoring tool that alerts the pipeline controller of a possible operating anomaly that may be indicative of a commodity release. Title 49 CFR 195.134 requires that CPM leak detection systems installed on a hazardous liquid pipeline must comply with American Petroleum Institute (API) recommended practice RP 1130.

[51] Line pack refers to the volume of material contained or stored within a pipeline.

imbalances. Enterprise reported that the CPM leak detection system was fully functional and assisted with the detection of the accident.[52]

6.5. Operating Pressure and Flow Rate

The maximum operating pressure (MOP) of Line TX219 was limited by the design pressure of one 16-inch diameter segment the pipe that was constructed of 0.250-inch wall thickness and API-5L, Grade B (yield strength 35,000 psi) steel pipe. Federal regulations at 49 CFR 195.106(a) prescribes a formula for determining the internal design pressure for a pipeline segment. Enterprise calculated the MOP for Line TX219 as follows:

$$\frac{2 \text{ x } 35{,}000 \text{ psi x } 0.250 \text{ in.}}{16 \text{ in.}} \text{ x } 0.72 \text{ (design factor)} = 787.5 \text{ psig}$$

The MOP percent specified minimum yield strength (SMYS) of the predominant pipe was 63 percent.[53]

Depending on the line pressure, the product flow can range from 100 bph to 470 bph at MOP.[54] The minimum operating pressure at no flow state for the pipeline was 200 psig in accordance with operating policy to ensure the propane remained in its liquid phase.[55] Typical operating pressure ranged between 250 and 300 psig and the flow set point was 420 bph as propane batches were received. The highest historical operating pressure of 701 psig occurred in 2016. During the month prior to the accident the operating pressure did not exceed 303 psig.

Enterprise Products conducted a pressure cycle analysis for the period October 6, 2017 through October 6, 2018 and concluded the pipeline had sustained “light” pressure cycling.

6.6. Pipeline Integrity Management

6.6.1. Surveys and Patrols

Enterprise surveils the pipeline using a combination of ground and aerial right-of-way patrols at intervals not exceeding 3 weeks, but at least 26 times each calendar year. Enterprise operations and maintenance procedures require that right-of-way patrols evaluate conditions at water crossings during flooding and after waters subside and determine if pipelines have

[52] Enterprise Products accident report number 20200256–34288 to the Pipeline and Hazardous Materials Safety Administration, Form PHMSA F 7000.1, September 18, 2020.

[53] The specified minimum yield strength for steel pipe is an indication of the minimum hoop stress a pipe may experience that will cause permanent deformation.

[54] Failure to maintain a minimum pressure and flow rate can result in measurement inaccuracy.

[55] Propane exists as a liquid at or below its boiling point of -44°F, as well as when it is stored under pressure. At a pressure of 200 psi, the saturation temperature (boiling point) of propane is about 104°F.

been exposed, undermined, or damaged. The patrols also observe and report such things as evidence of spills or discharges from pipeline facilities, dead vegetation, changes in the location of bayous, creeks, or riverbeds on or near the right-of-way, earth movement or subsidence, excavations within 200-feet of a company pipeline, heavy equipment on the right-of-way, unintentional exposure of pipelines, barges and watercraft anchored over river crossings, and damaged markers and signage. There were no known locations on pipeline TX219 where the condition of the right of way did not allow for inspection. Patrol observations were included in Enterprise's information analyses required under 49 CFR 195.452(g).

6.6.2. Inline Inspections

The Enterprise integrity management program described the necessary inline inspection tool capabilities for the detection of anomalies that could lead to pipeline failures. Since acquiring pipeline TX219, Enterprise's contractors performed three inline inspections (ILI) in 2009, 2011, and 2016.

In February 2009, T.D. Williamson, Inc. of Tulsa, Oklahoma, conducted ILI on pipeline TX219 in which it reported a total of 2,674 metal loss indications. T.D. Williamson reported the deepest indication was 68% of wall thickness. Two of the metal loss features, which were not in the vicinity of the accident location, prompted pressure reduction from the then MOP of 904 psig.[56] The inspection did not find any metal loss or dent indications that met criteria for immediate repair.

In November 2011, the Rosen Group provided Enterprise Products an ILI survey report that included the results of inspections for geometry and metal loss. The report stated that Line TX219 was affected mostly by internal corrosion anomalies, with the majority of metal loss indications between 10% and 19%. Nine deformation anomalies were found, with one affecting a seam weld. Rosen reported two locations with seam weld clusters of corrosion anomalies. The 2011 ILI report found no anomalies in the area where the pipeline was breached.

The data quality analysis contained in the Rosen Group 2011 ILI report for location accuracy at the accident location was ± 8.5 feet.[57]

In November 2016, the Rosen Group conducted the most recent inline inspection of Line TX219, which used circumferential magnetic flux leakage (CMFL) and Rosen's DEF

[56] T.D. Williamson, Inc. reported that the established maximum operating pressure at the location of the anomaly was less than the calculated remaining pipeline strength.

[57] The coordinate system used was World Geodetic System 1984 (WGS84). Enterprise provided the 2011 ILI location data to the National Pipeline Mapping System on March 3, 2020.

geometry inline inspection tools.[58] The CMFL tool is used to detect pipe wall anomalies such as pitting gouges, cracks, and hard spots. The CMFL tool is also capable of identifying weld anomalies, mill features, interior diameter anomalies, and wall thickness changes, among several other things.[59]

The 2016 inline inspection found 9 deformation indications on the pipeline that did not meet the depth criteria for repair as prescribed by 49 CFR 195.452(h)(4), or the criteria identified in the Enterprise pipeline defect evaluation and repair procedure. Although the inspection tools found no crack-like defects and no indications of stress corrosion cracking on the pipeline, the inspection did find 466 metal loss indications that did not meet criteria for repair. Most of the metal loss anomalies were internal corrosion, with between 10% and 19% wall loss. However, the inspection did identify 3 internal metal loss indications that required repair (see Section 6.6.4).

No anomalies were detected in the vicinity of the pipeline breach (GW 444000, Station 172+16). The geometry tool indicated the pipe wall thickness narrowed from 0.375-inch to 0.219-inch about 12 feet west (upstream) of girth weld 444000. The nearest internal metal loss indications were about 332 feet west (35% depth + tolerance) and about 69 feet east (40% depth + tolerance) of the accident location.

Smart pig tools used in ILI surveys carry inertial navigation packages that the ILI vendor uses to calculate GPS coordinates at each logging event. For the 2016 ILI survey, the Rosen Group used a combination of 11 reference tie-in points (RTPs), which included temporary above ground markers (AGMs) and known valve locations as benchmarks for enhancing location accuracies. The location accuracy for a given pipeline segment is dependent on the distance between RTPs and the inspection tool velocity for the area. Based on the odometer distance contained in the ILI report, Rosen's data quality summary indicated that the expected location accuracy in the 2016 ILI report for the segment including girth weld 444000 was ± 3.3 feet.[60]

6.6.3. Corrosion Prevention

Enterprise employed an impressed current cathodic protection system to protect the pipeline from external corrosion threats.[61] On July 13, 2018, Enterprise completed a corrosion

[58] Circumferential magnetic flux leakage inline inspection tools are used detect and quantify defects such as cracks, seam weld defects, mechanical damage, and corrosion. Geometry tools assess deformations in pipelines such as dents and buckles that cause stress concentrations capable of initiating fatigue failures.

[59] The capability and features of Rosen Group pipeline inspection tools are further described on the company website at: https://www.rosen-group.com/global/solutions/services/inspection.html

[60] J. Morton, Enterprise Products Partners L.P., letter (regarding response to NTSB March 15 Requests for Clarification) to L. Wisniewski, National Transportation Safety Board, March 26, 2021.

[61] Impressed current cathodic protection systems halt electrochemical corrosion processes using sacrificial anodes connected to an external power source that drive current through the environment and onto the pipeline.

prevention evaluation for Line TX219, which determined from periodic field surveys of monitoring sites along the pipeline that annual pipe to soil electrical potential measurements exceeded minimum established criteria of -850 mV for the years 2015 through 2018. In addition, Enterprise's cathodic protection annual survey reports for 2018, 2019, and 2020 identified no segments on the pipeline where the electrical potential was below minimum criteria established by its integrity management program. Enterprises atmospheric survey reports for 2018 and 2020 also found no evidence of corrosion at soil-to-air interfaces on the pipeline.

For internal pipeline corrosion control, Enterprise tested the liquid propane for the presence of corrosive constituents and used cleaning pigging. Enterprise did not inject corrosion inhibitors or use internal pipe coatings or linings in the pipeline.

6.6.4. Pipeline Maintenance and Repairs

Prompted by the results of the November 2016 inline inspection findings in which internal metal loss indications required repair, Enterprise records indicate a repair was made to Line TX219 during 2017. The repair involved excavating a 10-ft. pipeline segment at Station 226+97, near Origin Station between MP 4 and MP5. The repairs were not located within 1-mile of the accident scene at Station 172 +16. The metal loss indications were repaired with Type B sleeves or recoating.[62]

To keep the pipeline free of debris and functioning efficiently, Enterprise Products ran cleaning pigs through the pipeline annually.

Enterprise most recently visually inspected, operation tested, and greased Viola Station motor operated valve MOV-20 on June 16, 2020. Viola Station motor operated valve SDV-25 was similarly last inspected prior to the accident on March 16, 2020.[63] In addition, 6-inch and 8-inch manual valves at Cantwell Station that were used on the day of the accident to isolate Line TX219 from Line M4-6 and Origin Station tank storage were inspected on April 30, 2020 and March 31, 2020, respectively. Enterprise pipeline technicians did not identify any failed inspection points.

Furthermore, Enterprise records have not identified any repair documentation from the previous pipeline operator, Exxon Pipeline Company, within one mile upstream or downstream of the incident location.

[62] A Type B sleeve is completely welded to the pipe and is used to contain a leak or to reinforce an area where a defect exists.

[63] In accordance with the valve maintenance requirements of 49 CFR 195.420, an operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding 7 ½ months, but at least twice each calendar year.

6.6.5. Hydrostatic Testing

To establish baseline integrity assessments of pipeline segments, the Enterprise integrity management procedures required hydrostatic tests to be conducted in accordance with 49 CFR Part 195 subpart E for newly constructed or conversion-to-service pipelines prior to beginning operation or changing service. Enterprise hydrostatically tested pipeline TX219 at about 1,130 psig on July 7, 2006. Records indicate the previous operator, Exxon Pipeline Company, also conducted a hydrostatic test on the pipeline in 1995. Neither test identified any leaks or failures.

6.6.6. High Consequence Area Risk Assessment

The Enterprise integrity management program calls for integrity assessments to be conducted of 49 CFR Part 195 jurisdictional hazardous liquid pipelines that have been identified within HCAs, as well as Texas Intrastate pipeline segments that have assessment requirements. Enterprise conducted two types of periodic evaluations of pipeline threats that used results from risk assessments: The Information Analysis (IA) process and the Assessment Method Selection (AMS) process. Dynamic Risk Ltd. provided the algorithms and tools Enterprise used to consider multiple variables for developing relative risk scores for its pipeline segments. Because the risk scores are only one data element used in the holistic IA and AMS risk assessments, thresholds have not been established that would trigger further mitigative action. Rather, the risk scores are a tool Enterprise integrity engineers used to recommend what data should be examined in greater detail to support the IA conclusions and recommendations.

The IA involved analyzing integrity assessment inspection results and other information about the pipeline and determining the need for any additional remediation requirements, further monitoring, and/or additional preventative and mitigative measures or modifications to existing programs.[64] The integrity management program required an IA to be conducted within two years of completing integrity assessments such as inline inspections.

Enterprise used the AMS process to determine the type of integrity testing necessary for a given pipeline segment, such as whether the segment should be subjected to hydrostatic testing or inline inspection. The AMS process also identified specific requirements for each testing method.

Accordingly, Enterprise identified the specific requirements for the 2016 inline inspection using the AMS process. On October 19, 2018, the Enterprise pipeline integrity engineering team performed an IA using the 2016 inline inspection results in combination with the Dynamic Risk Ltd risk assessment spreadsheet tool. This IA used data that Enterprise compiled

[64] The information analysis is required by 49 CFR 195.452(g), which describes the required elements of an integrity management program.

during the first quarter 2018. The IA considered risk factors pertinent to the history of the pipeline operations, configuration, integrity inspections, prior incident data, and potential threats to public safety, health, and the environment.

Based on Enterprises' data inputs for the pipeline, the Dynamic Risk Ltd. algorithms assigned risk score values to various threat categories. These categorical scores were then used to compile scores for overall probability and for overall consequence. The total risk scores were the mathematical product of the probability and consequence scores. However, the IA tool contained risk data for 126 segments of Line TX219, each of varying length and risk profile. Thus, the reported total risk, probability, and consequence scores used in the IA were compiled of segment length-weighted averages.[65]

For the 2018 IA, overall risk scores Enterprise assigned to pipeline TX219 were a total risk score of 18.96 (range 0-100, with 100 being the riskiest), a total probability score of 3.45 (range 0-10), and a total consequence score of 5.50 (range 0-10).

The 2018 IA evaluation of Enterprise's third-party damage prevention program found that the pipeline had no in-service releases since the previous assessment. The Enterprise pipeline integrity engineering team further noted there were no recorded incidents or near misses attributable to third-party damage. The third-party damage categorical score was 1.32 (range 0-10) and was factored along with 8 other threat areas into the total probability score of 3.45.[66] To do this, the third-party damage score was multiplied by a 16% likelihood of failure factor, which is based on industry causal prevalence data.

The 2018 IA did not recommend any modifications of the Enterprise programs addressing third-party damage prevention, nor did it recommend additional rehabilitation activities for the pipeline. Additionally, no additional improvements were recommended for other integrity management programs such as leak detection or external and internal corrosion prevention. The integrity engineer recommended that the integrity reassessment for the threat of pipeline deformation and, metal loss anomalies, and longitudinal seam failures should be conducted within 5-years from the date of the 2016 assessment (the regulatory maximum interval). Further, the integrity engineer considered the lack of stress corrosion cracking (SCC) evidence when Enterprise conducted magnetic particle inspection of exposed pipe during rehabilitation activities. Nevertheless, he concluded that the potential susceptibility of the pipeline to SCC

[65] P. Stancil, National Transportation Safety Board, memorandum (virtual meeting with Enterprise Products regarding risk analysis documentation), to Dredge Waymon Boyd investigative information (DCA20FM026), February 10, 2021.

[66] The eight other threat areas Enterprise Products used to determine the probability of an incident included external corrosion, stress corrosion cracking, internal corrosion, manufacturing defect, construction threat, equipment failure, outside force, and incorrect operations.

warranted additional data collection and analysis where the pipe lacked fusion-bond epoxy coating and where no SCC had yet been identified.

During the first quarter 2020, Enterprise conducted its most recent risk assessment for Line TX219 prior to the accident, which is reflected in a 2020 detailed risk analysis spreadsheet. Among the data categories contained in the spreadsheet for risks associated with third-party damage were signage, right of way exposure, casing presence, and depth of cover. Each of these columns listed "null" for all 126 rows of pipeline segments, which means an assumed default value was automatically assigned in the algorithm since there was no available data for these factors. For example, the default value for depth of cover equated to an assumed 3 feet of cover, which is the typical as-constructed depth of cover requirement for this geographic location. The spreadsheet algorithm assigned third-party damage risk score of 1.645 (range of 0-10) for the 730-foot segment of pipeline on which the accident occurred. Many adjacent pipeline segments were given the same third-party damage risk score of 1.645, which was the highest risk ranking in this category for TX219. The lowest third-party damage risk ranking was 0.5 for one short segment of only 43 feet.

For the first quarter of 2020, the overall risk score for TX219 was 15.43 (range 0-100), the total probability score was 2.81 (range 0-10), and the total consequence score was 5.50 (range 0-10).

6.6.7. Mitigation of Identified Threats to TX219

Enterprise Products acknowledged that there were three threats to the portion of Line TX219 located near the shoreline of the Corpus Christi Ship Channel: third-party line strikes associated with excavation activities; corrosion; and vessel traffic in the waterway.[67]

To mitigate third-party damage threats, Enterprise Products registered Line TX219 with the Texas state One-Call center and responded to line locate tickets for proposed excavations and/or dredging activities in the vicinity of the pipeline. Enterprise also conducted aerial patrols as described in Section 6.6.1.

Corrosion threats were monitored through inline inspection activities and mitigated as described in Section 6.6.3.

Enterprise told NTSB investigators that vessel traffic in the waterway is limited to vessels that have received special authorization, and the channel is closed to general maritime traffic, such as recreational vessels. Furthermore, maps of the accident location indicate the section of Line

[67] J. Morton, Enterprise Products Partners L.P., letter (regarding NTSB Party Representative Records and Information Requests) to L. Wisniewski, National Transportation Safety Board, December 11, 2020.

TX219 located near the shoreline within the waterway was over 350 feet from the toe of the shipping channel.

6.7. Emergency Shut Down Procedures

The Enterprise emergency response plan stated that the nearest upstream and downstream valves should be shut during an incident such as a line rupture, provided they can be safely accessed. The plan further stated that for a large product releases and fires or explosion, emergency shut down valves and remote closing valves should be activated as needed.

For pipeline segments located within HCAs, Enterprise Products operating procedures and systems were designed for SCADA monitoring, valve location, and response personnel to provide pipeline rupture detection within 5 minutes, pipeline shutdown within 15 minutes, and an on-scene response time of 30 minutes.

If an abnormal operating condition or emergency condition existed, such as any unexplained pressure drop or sudden change in flow rate, Enterprise emergency response procedures stated the operator should consider the potential of a leak. The procedures stated the controller should use available trending tools to determine if the situation suggests that a leak has occurred. If the controller is unable to confirm whether a leak has occurred, the controller must notify the nearest station personnel to request an investigation.

The Enterprise pipeline controller had the authority and responsibility, without referral to management for approval, to shut down any pipeline system upon receiving a report or indication of an emergency condition, including closing isolation valves upstream and downstream of a leak. Upon verifying that an emergency condition exists, the procedures state that pipeline control and field personnel efforts must be directed to securing the area by isolating the pipeline segment.

6.8. Personnel Qualifications

6.8.1. Pipeline Controller

The pipeline controller who was on duty at the time of the accident had been qualified by Enterprise as a controller for 5 years, during which time he gained experience operating pipeline TX219. He was responsible for simultaneously controlling between 5 and 10 pipelines during a 12-hour shift. His training included an initial 6-to-8-month in-service training period. He received annual recurrent training that covered new and existing company procedures in pipeline control.[68]

[68] Enterprise Products pipeline controller, p. 10-13.

Enterprise provided pipeline controllers recurrent certification evaluations at 36-month intervals. The pipeline controller on duty at the time of the accident was last evaluated on March 21, 2019 and scored successful in each job performance verification topic. The evaluation involved the operator's response to abnormal facility conditions and control system indications, such as flow rate changes that could not be explained. The evaluation also included such topics as recognition and response to activate safety devices, emergency shut down system operation, ensuring facility isolation devices operate to shut in the pipeline system, determining the cause of an emergency shut down, and notifying appropriate personnel.

The pipeline controller had not been involved with any other pipeline in-service failures during his tenure with Enterprise Products.

6.8.2. Hazardous Liquids Pipeline Technician

The hazardous liquids pipeline technician who participated in the July 2020 One-Call ticket review for Line TX219 prior to this accident had been employed by Enterprise for 4 years, 11 months. His educational background included attendance at Del Mar College for firefighting, fire science, and emergency medical services. Prior to his employ with Enterprise, he was a firefighter for 5 years and then was employed as a safety consultant for local refineries in Corpus Christi for 2 years.

His daily duties included reviewing One-Call tickets and overseeing pipeline integrity work such as anomaly repairs. In addition, he coordinated right-of-way mowing, facility maintenance, painting of above ground piping, and valve inspections. In a typical work day, the hazardous liquid pipeline technician responded to about 10 to 12 One-Call tickets.[69]

On-job training included the Enterprise Products Right-of-Way College in 2016, and refresher training in 2018. Among the other on-job training the hazardous liquids pipeline technician attended were:

- Annual hazardous liquid training review required by 49 CFR 195.403,
- OSHA Hazwoper Operations level,
- Hazardous materials transportation regulatory requirements,
- Korterra ticket management system rollout training for One-Call ticket management system,
- Operator qualification evaluator training to qualify employees to be a DOT Operation Qualification Evaluator,
- Process Safety Management (PSM) overview, and
- Emergency plan overview, training on site specific response to local emergencies.

[69] Enterprise Products hazardous liquids pipeline technician, p. 9-10.

6.8.3. Gas Pipeline Technician

The gas pipeline technician who participated in the One-Call ticket review for TX219 has been employed with Enterprise for 4 years in his current capacity. His prior employment included working as a contractor for Phillips 66 and Enterprise Products specializing in pipeline damage prevention.

The gas pipeline technician estimated that 90 percent of his job duties involve reviewing and responding to One-Call tickets, with workload of about 10 to 15 tickets each day. His duties also included damage prevention, pipeline maintenance, and conducting pipeline equipment inspections.[70]

His on-job training included the Enterprise Products Right-of Way College, which he initially completed in 2017, along with refresher training in 2019. Among the training topics included in the Enterprise Products Right-of-Way College and other courses the gas pipeline technician attended were:

- Annual hazardous liquid training review required by 49 CFR 195.403,
- OSHA Hazwoper Operations level,
- Hazardous materials transportation regulatory requirements,
- Process Safety Management (PSM) and maintenance overview,
- Enterprise preventative maintenance and tracking system,
- ROW pipeline location – install, inspect, and maintain permanent and temporary markers,
- Manually and remotely opening and closing valves,
- Performing maintenance on valves,
- Inspecting for physical damage on buried or submerged pipe,
- Inspecting buried pipe when exposed,
- Operating odorant equipment,
- Leakage survey techniques, and
- Emergency plan review, site-specific response to local emergencies.

6.9. Texas Permit to Operate

Texas Administrative Code, Title 16, Rule 3.70 requires all operators of a pipeline system to have a T-4 pipeline permit issued by the Railroad Commission of Texas. The T-4 pipeline permit collects information about the pipeline operator and the pipeline characteristics.

On March 9, 2018, the Railroad Commission of Texas issued Permit to Operate Number 07403 to Enterprise Products Operating LLC, granting authority to operate in 296.6 miles of pipeline

[70] Enterprise Products gas pipeline technician, p. 10-11.

associated with their Shoup to Mont Belvieu, South Texas Gathering-TX140 and Morgan's Point System, which includes the accident pipeline TX219. The permit was valid for either one year from issue date or until a change in ownership, operations, or commodities transported occurs. Enterprise possessed an additional 30 intrastate and 11 interstate pipeline permits issued by the Railroad Commission.

Additional documentation Enterprise provided to the Railroad Commission included an August 31, 2006, Pipeline Transfer Certification to report its acquisition of pipeline TX219 from its previous operator, ExxonMobil Pipeline Company.

7. Protection of Pipelines from Excavation Activity

Federal pipeline safety regulations at 49 CFR 195.442 require that for hazardous liquid pipelines, the operator of an underground pipeline must develop a written program to prevent damage to the pipeline from excavation activities.[71] The pipeline operator may comply with the requirements of this regulation through participation in a public service program, such as a One-Call system, and must be covered by a qualified One-Call system where there is one in place.[72]

In addition, 49 CFR Part 196 prescribes the minimum requirements that excavators must follow to protect underground pipelines subject to PHMSA or state pipeline safety regulations from excavation-related damage. Among these requirements, prior to and during excavation activity the excavator must use an available One-Call system before excavating to notify pipeline controllers of the timing and location of the intended excavation. The regulation requires that if underground pipelines exist in the area, the excavator must wait for the pipeline controller to mark the location of its pipelines before excavating.

7.1. Enterprise Products Damage Prevention Program

The most recent revision of the Enterprise damage prevention program became effective May 4, 2016 and contained protocols and procedures that were intended to address company policies and applicable federal, state, and local regulations. The program stated that Enterprise participates in a qualified One-Call system in every state in which it operates.

The program directed personnel assigned to locating pipelines (line locators) to, among other things, contact the One-Call ticket originator to discuss the exact location of the excavation as

[71] The Enterprise Products damage prevention program defines underground pipelines as those located partially or totally underground.

[72] Title 49 CFR 198.37 requires that each area of a state that contains underground pipeline facilities must be covered by a One-Call notification system in which excavators must notify the system of each intended excavation activity. The One-Call notification system transmits notices to operators of underground pipeline facilities and other underground facilities that participate in the system.

defined on the ticket, and the planned activities at the excavation site.[73] Line locators were also directed to determine if the area of excavation was properly identified in the One-Call ticket, as well as the direction, distance, and start and stop locations of proposed excavation activity. The line locator was supposed to record notes of the conversations or meetings with the ticket originator in the One-Call ticket. In 2014, for example, records indicate that Enterprise responded to 8,470 One-Call notifications in Nueces County, Texas alone.

According to the program, a site visit may not be required if contact with the ticket originator has determined that, "without question," the excavation activity falls outside of designated buffer zones or rights-of-way. However, the line locator must conduct a site visit if any questions exist. If the site meeting determined that the excavation posed no risk to Enterprises' pipelines, the line locator was to complete the One-Call ticket with a status of "Cleared." If the meeting determined that a planned excavation would pose a risk to the pipeline, the program called for the pipelines to be located and marked, and the One-Call ticket status to be identified as "Marked."

The program also provided for required marking areas and marking frequency. For excavations occurring within 50 feet of the centerline of Enterprise's pipelines, the pipeline must be located and marked at intervals of 20 feet. In surveying the pipeline to mark its location, the line locator is supposed to use an electronic line locator instrument in which an electronic signal is transmitted to the target pipeline and located with a handheld receiver. The program further provided that for any excavation within 12 feet of a pipeline, Enterprise field personnel must be on site to monitor excavation. Excavations and encroachment activities outside of 12 feet could be monitored by Enterprise representatives as needed based on the judgement of company management.

The damage prevention program provided that after receiving a One-Call notice for a large project that could potentially impact pipeline facilities, Enterprise and the excavator may jointly establish an excavation protocol agreement applicable to the excavation site near company pipelines. Such protocol agreements must detail the scope of work and include GPS coordinates for the beginning and ending points of the planned project and any points of inflection.

The program required that temporary markings used for locating pipelines must follow APWA uniform color code. The program stated that where applicable, temporary markers such as buoys, poles, or PVC markers should be used to indicate the location of underwater pipelines. If necessary, these markers could be supplemented with mapping, GPS coordinates, and/or fixed high-bank marks.

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[73] A One-Call ticket is a record of the notice of intent to excavate given by the excavator to a notification center in conformance with state one-call regulations.

Although they were familiar with the requirements for marking frequency, marker types, and color codes, the Enterprise gas and hazardous liquid pipeline technicians did not have previous experience marking pipelines that were located in water parallel to the shoreline.[74]

7.2. Enterprise Products Pipeline Public Awareness Program

Title 49 CFR 195.440 requires that each pipeline operator develop and implement a continuing public education program that follows the guidance provided in the American Petroleum Institute (API) recommended practice RP1162.[75] The Enterprise public awareness program relied on patrols, surveys, maintenance of pipeline rights-of-way and other activities to increase pipeline visibility in areas accessible by the public. Pipeline safety information available to the public is found on the Enterprise company website.[76]

Enterprise told NTSB investigators that its public outreach efforts include participation in collaborative industry sponsorships and other local events that are targeted at increasing pipeline safety awareness when excavating. These include, but are not limited to, membership in the Common Ground Alliance, the Coastal and Marine Operators Group, and participation in annual collaborative liaison meetings with emergency officials and excavators.

In addition, Enterprise distributed through direct mailouts pipeline awareness brochures, which were published in English and Spanish.[77] The brochures advised addressees they had been identified as an individual or organization who has conducted, or may conduct, excavation or development near a pipeline operated by Enterprise Products. The brochures contained public safety messages and encroachment guidance to stakeholders and excavators in which they were urged to contact 811 prior to any digging project. The brochure stated that Enterprise's policy requires a company representative to be on site for all excavations that take place within 12 feet of a company pipeline to ensure safety. It further stated that the policy requires hand digging when working within the tolerance zone of a pipeline. Brochures also contained pipeline emergency recommendations, leak recognition information, and company website links for additional information about pipeline safety and damage prevention.

Following a near miss or third-party damage incident, Enterprise verified whether a One-Call was made and also whether the excavator had been added to the company's public awareness stakeholder database. If not, the excavator was added to the mailing list to receive periodic pipeline safety public awareness communications as recommended by API RP1162. The

[74] Enterprise Products gas pipeline technician, p. 54.

[75] *Public Awareness Programs for Pipeline Operators,* API Recommended Practice 1162 Second Edition (Washington, DC, American Petroleum Institute, 2010).

[76] https://www.enterpriseproducts.com/safety-environment/public-awareness, accessed February 16, 2021.

[77] The Enterprise Products public awareness program states that the affected public receives mailouts every two years, whereas excavators receive mailouts annually.

Enterprise stakeholder data base also included such organizations situated within a certain distance of Enterprise's pipelines. The Orion Group had been listed in the Enterprise public awareness stake holder database and had received annual pipeline safety brochures over the past five years.[78]

Furthermore, Enterprise had published a separate encroachment guidelines brochure that directed excavators not to perform excavation activities on rights-of-way without Enterprise's approval.[79] The guidelines explained the information excavators must provide in connection with 811 One-Call notifications, such as a description of the project, map of the project location, and detailed construction plans depicting existing and proposed surface elevations, pipeline location, and depth. The guidelines also advised that in some cases Enterprise may determine that an adjustment, relocation, or lowering of a pipeline may be necessary to ensure the safety of a proposed project and the integrity of the pipeline.

The encroachment guidelines further stated that mechanized equipment is not allowed to conduct excavation activities within a tolerance zone, defined by Enterprise as 18 inches from the outer edge of the pipe in all directions or as defined by state regulations.[80] The guidelines stated that any excavation taking place within the tolerance zone must be done by hand. General excavation guidelines add that all mechanical digging equipment must dig parallel to pipelines and have the teeth removed or barred with a plate welded across the bucket.

7.3. Orion Group Procedures for Avoiding Infrastructure Damage

Orion Group did not have written procedures describing the protection of utilities and infrastructure located outside of the excavating area template on DREDGEPACK®. Further, at the time of the accident, Orion did not have written procedures, precautions, or dredging best practices when excavating near infrastructure and utilities.

However, Orion told NTSB investigators that the company's general operating practices included:

- *Review dredging plans as provided by client,*
- *Perform One Call notifications,*
- *Gather information from pipeline controllers,*
- *Make sure the line is marked and get details of markings from pipeline controllers,*

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[78] The Enterprise Products stakeholder database also contains the email addresses of five Orion Group officials.

[79] *Enterprise Products Encroachment Guidelines* (Houston, Texas, Enterprise Products Partners L.P., rev. May 2019).

[80] Title 16, Part 1, Chapter 18.2 of the Texas Administrative Code defines a tolerance zone as half the nominal diameter of the underground pipeline plus a minimum of 18 inches on either side of the outside edge of the pipeline on a horizontal plane.

- *Information sent to captain and relayed verbally regarding pipeline details,*
- *If GPS coordinates are provided, upload onto the digging screen,*
- *No digging within 10' of any permanent structures.*

Precautions Orion Group crews normally took when dredging near or over pipelines involved turning off the cutterhead motor and securing the cutterhead from any possibility of rotating with cable wrapping. Company procedures for dredging near any pipeline involved using only the suction head to remove sediment.

Occasionally for other projects, pipeline company employees have boarded the dredge to observe when operations came close to pipelines. However, there were no Enterprise Products employees aboard the *Waymon Boyd* during the EPIC East Dock project.

The deck captain was unaware of any company policy governing how close cutterhead dredging may be performed near a pipeline. However, Orion Group dredge management stressed that crews should avoid dredging more than one foot outside the project template because the company does not get paid for removing extraneous material.[81]

The director of health, safety, and environment stated Orion defers to the utility owner when establishing the tolerance zones for working near pipelines. He stated that the company prefers to dredge no closer than 20 feet from pipelines. He added that Orion has no written policy addressing pipeline stand-off distances. Questioned whether the company follows dredging best practices published by such organizations as the Council for Dredging and Marine Construction Safety (CDMCS), the director of health, safety, and environment responded that Orion uses its own internal methods and best practices for avoiding pipelines while dredging, which he stated are very similar to the CDMCS checklist and standard throughout the industry.[82]

7.4. Dredging Project One-Call Records

7.4.1. Dredging Project First Phase

On May 7, 2019, the Orion Group project manager filed two One-Call (811) pipeline locate requests through KorTerra to verify if dredging operations conflicted with Enterprise pipelines near the area, one for each active pipeline – hazardous liquid pipeline TX219 and gas pipeline 124-1.[83] The Enterprise gas and hazardous liquid pipeline technicians visited the EPIC project

[81] Orion Group dredge captain, p. 23–25 and Orion Group deck captain, p. 26-28.

[82] NTSB interview of the Orion Group director of health, safety, and environment, April 9, 2021, p.26-28.

[83] KorTerra ticket number TX1962741283CA for pipeline 124 and ticket number TX1962741283CB for pipeline TX219. KorTerra is an Enterprise internal Web-based One-Call ticket management for underground asset and infrastructure protection. Excavators file One-Calls through the state One-Call notification center, Texas 811.

site and met the EPIC lead inspector who confirmed that dredging activity would take place in the shipping channel north of the pipelines and would not impact pipeline TX219. The EPIC inspector agreed to install cane poles himself to mark the pipeline.[84] The Enterprise gas and hazardous liquid pipeline technicians returned to the site a couple of days later confirm the cane poles had been installed and noted they were visible in the waterway from land.[85]

The Enterprise gas pipeline technician closed the ticket for line 124 on May 14, 2019, indicating that he visited the site and spoke to the project manager, and that Enterprise line 124 was located 65 feet to the south of the project and will not be affected. The Enterprise hazardous liquid pipeline technician closed the one call ticket for pipeline TX219 on May 14, 2019, noting that he met with the excavator (Orion) on site and that all work would be done inside of the ship channel and Line TX219 would not be affected.

The Orion Group completed the first phase of the dredging by mid-July 2019, subsequent to the 2019 One-Call tickets, without any impact to Enterprise pipelines.

7.4.2. Dredging Project Second Phase

On June 23, 2020, the Orion Group project engineer, who had not been involved with the first phase operations, filed a One-Call pipeline locate request through the state One-Call notification center, Texas 811 to locate pipelines in the vicinity of the EPIC proposed East Dock dredging project. The One-Call ticket work location details stated the excavation depth was -47 feet, with a length of 1,400 feet. The One-Call location details further provided the following geographic coordinates:

NW CORNER: 27.81733, -97.46952
SW CORNER: 27.81625, -97.46921
NE CORNER: 27.81644, -97.46507
SE CORNER: 27.81563, -97.46600

The Orion Group project engineer used a KMZ file of the dredge template in Google Earth to obtain these coordinates by inserting placemarks on the corners of the dredge area.[86] NTSB investigators plotted these coordinates along with Orion Group dredge template coordinates using the HYPAK 2018 module (Figure 14).

[84] Cane poles are bamboo poles about 18 feet in length.
[85] Enterprise Products gas pipeline technician, p. 18.
[86] Orion Group project engineer, P. 54.

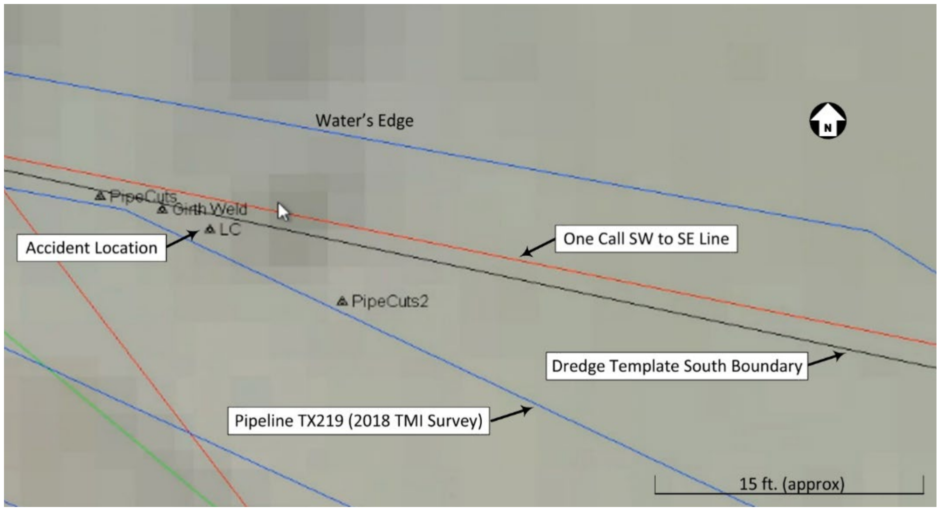

Figure 14. Plot in the HYPACK 2018 module of the Orion Group June 23, 2020 One-Call notification coordinates that were used to draw a southeast to south west line (red line), the Orion Group dredge template south boundary (black line), and pipeline TX219 location determined by the TMI Solutions LLC, December 28, 2018 utilities survey (blue line). The Enterprise Products pipe cut location survey and the accident location are also shown for reference. Courtesy HYPACK, a Xylem brand with NTSB annotations and approximate scale.

The one call ticket also stated:

> *DREDGING AREA BEINGS AT WATERS EDGE (SE CORNER GPS POINT NOTED BELOW) AND EXTENDS NORTH OFF THE COAST 344~ TO THE NORTHERN BOUNDARY OF DREDGE TEMPLATE. THE LENGTH EAST-WEST OF THE TEMPLATE IS 1,463~ BETWEEN 27 48 59.15 N, -97 27 54.34 W AND 27 49 2.46 N, -97 28 10.29 W*

The Orion project engineer referred to a Google Earth dredge template KMZ file prepared by Orion's survey department to identify the coordinates of the corners of the dredge template area she entered into the One-Call ticket project description.[87] The description of the work location indicated that the excavation area had not been white lined.[88]

Questioned by NTSB investigators how the Orion project engineer determined the "dredging area begins at water's edge," she responded:

> *So that means, while the template does have a slope, we do encompass more area than the actual template to account for swing anchors.*[89]

[87] Orion Group project engineer, p. 54.
[88] White lining is the practice of marking the proposed excavation area using white paint or stakes with white flags prior to the arrival of the utility locator(s).
[89] Orion Group project engineer, p. 54.

The state One-call notification center dispatcher identified Enterprise Products pipelines near the proposed work area and forwarded two One-Call tickets to Enterprise on June 23, 2020, ticket number TX2067555147CA for natural gas pipeline TX124, and ticket number TX2067555147CB for hazardous liquid propane pipeline TX219. Also, on June 23, 2020, the Enterprise gas pipeline technician telephoned the Orion project engineer and discussed the nature and scope of the project. Based on their initial review of the One-Call ticket, the Orion project engineer and Enterprise gas pipeline technician agreed the pipelines would likely require locating and marking. The project engineer also agreed that Orion would provide a boat and cane poles to mark the pipeline and they scheduled a job site meeting for June 30, 2020.[90] The Enterprise Products gas pipeline technician who was responsible for locating pipeline TX124 also informed the hazardous liquids pipeline technician responsible for locating TX219.[91]

On June 24, 2020, the gas pipeline and hazardous liquid pipeline technicians classified the One-Call tickets as "5-Locate Delayed" pending the planned meeting and determination of the Orion Group's final excavation location.

In the meantime, the project engineer telephoned the gas pipeline technician to advise that the scheduled June 30 onsite meeting had to be cancelled due to COVID-19-related logistics. The Orion project engineer told NTSB investigators that she requested GPS coordinates for the pipeline from the gas pipeline technician, but the technician reportedly replied that he did not have any GPS data.[92] As an alternative to meeting on site, on June 29, 2020, the project engineer emailed the Schneider Engineering June 23, 2020 dredging construction plans to the gas pipeline technician for review.[93] On that day, the gas pipeline technician forwarded the email to the hazardous liquid pipeline technician.

The Orion project engineer's email to the Enterprise Products gas pipeline technician stated:

> *I've attached the latest plans. Page 2 shows existing pipelines in blue, I'm assuming a couple of those are yours. Page 3 shows our new dredge prism for phase II of dredging. It looks as though we will be about 60' off the shoreline, and the areas where the shoreline and pipelines are furthest in the water (closest to the new template), we have already completed dredging to grade (where the dock platform is on page 3) so there shouldn't be a need for concern.*

[90]Enterprise gas pipeline technician, p. 18.

[91] The Enterprise gas technicians who processed the June 23, 2020 One-Call tickets were the same individuals who processed the May 7, 2019 One-Call tickets.

[92] Orion Group project engineer, p. 34.

[93] EPIC Marine Terminal Dredging Construction Plans for EPIC Crude Terminal Company, LP, Corpus Christi, Texas, (Schneider Engineering & Consulting, June 23, 2020).

When NTSB investigators questioned the Orion project engineer about the origin of the 60-foot distance referenced in her email to the Enterprise pipeline technicians, she replied:

> "*That is what I presumed when I provided the plans. But I was taking into account phase one, and I could be wrong.*"[94]

Questioned how far outside the dredge template were the pipelines located, the Orion project engineer responded, "far enough away." The Orion Group project engineer further told NTSB investigators that the determination the pipelines were located outside of the dredge template was made by the Orion Group project manager with input from the Orion survey department. The project engineer explained that Orion conducted a "before dredge" survey that was overlaid on available information that did not include any GPS coordinates for the pipeline, and therefore she was not able to provide a precise clearance distance.[95]

On June 30, 2020, the Orion project engineer emailed the Enterprise gas pipeline technician to inquire if the company had reviewed the dredge plans. Also, on June 30, the project engineer telephoned the gas pipeline technician, who informed her that he and his supervisor had reviewed the plans and they concluded the dredging would be clear of the pipelines.[96] The pipeline technicians used GIS data for Line TX219 contained in a Google Earth KMZ file in their review of the locate tickets (see Figure 27).

The Enterprise gas and hazardous liquid pipeline technicians told NTSB investigators they discussed the dredge construction plans forwarded by the Orion project engineer. The gas pipeline technician said:

> *We looked at the EPIC plans and saw the prism where [the project engineer] said that we're going to be working, and it was well offshore. And with the knowledge that EPIC wanted to put in a bulkhead and fill in our lines with sand, we knew we were okay with clearing that ticket.*[97]

The Enterprise gas pipeline technician further stated that based upon the Orion project engineer's June 29, 2020 email and as a result of his discussion with the Orion project engineer, he understood the southern boundary line of the prismatic area on the plan (identified by the yellow arrow in Figure 15) was supposed to represent the closest location that dredging was to occur near the Enterprise pipelines. The pipeline technicians did not use the plans Orion supplied to calculate the distance between the pipeline and what they understood to be the

[94] Orion Group project engineer, p. 48.
[95] Orion Group project engineer, p. 20 -21, 56 – 57.
[96] Orion Group project engineer, p. 35.
[97] Gas pipeline technician, p. 19, 26.

dredge boundary. The gas pipeline technician said their knowledge that EPIC planned to construct a bulkhead and fill over the pipelines with sand provided them added comfort with clearing these One-Call tickets.[98]

Figure 15 is an excerpt of page 2 of the EPIC Marine Terminal dredging construction plan that the Orion project engineer emailed to the Enterprise gas pipeline technician showing the proximity of the pipelines to the proposed dredge project.

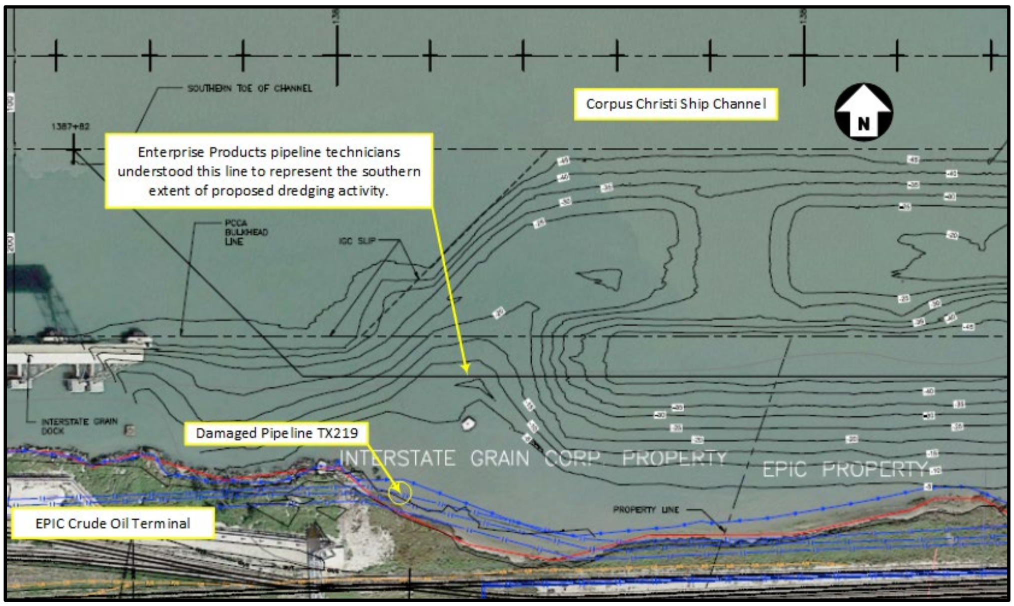

Figure 15. Annotated excerpt of the Schneider Engineering EPIC Marine Terminal dredging construction plan the Orion Group project engineer emailed to the Enterprise Products gas pipeline technician on June 29, 2020. Annotations indicate the Enterprise Products pipeline technician's understanding of the southern boundary of the dredging project and the location of propane pipeline TX219 (yellow arrows). The approximate location of the pipeline damage is indicated by the yellow circle.

Figure 16 is an excerpt of page 3 of the EPIC Marine Terminal dredging construction plan the Orion project engineer referenced as having already completed dredging to grade at the dock platform location.

[98] Gas pipeline technician p. 18-19, 23-24, 31, 81; hazardous liquid pipeline technician p. 17, 25.

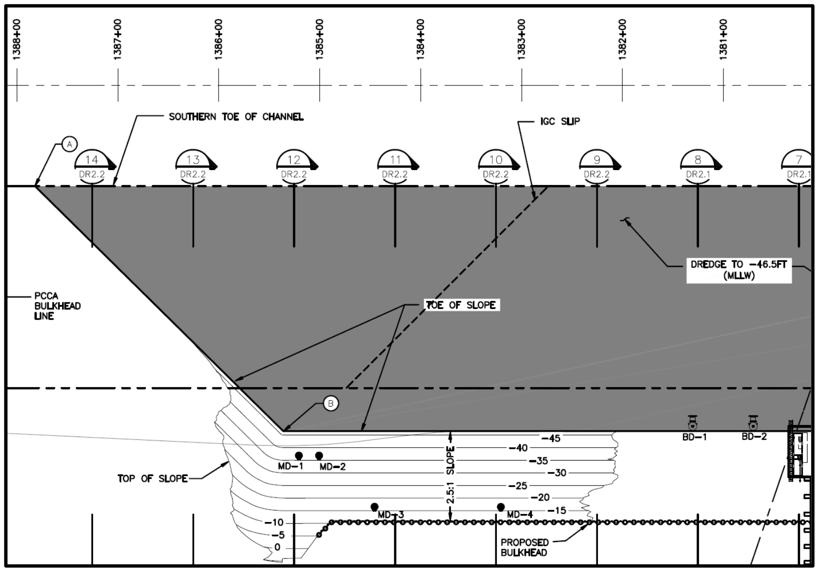

Figure 16. Excerpt of EPIC Marine Terminal dredging construction plan the Orion project engineer emailed to the Enterprise Products gas pipeline technician on June 29, 2020 indicating the dredge limits shaded in gray.

On June 30, 2020, the hazardous liquids pipeline technician completed One-Call ticket TX2067555147CB with a "3-Clear" response, remarking, "Pipeline TX219 will be clear from work area by 55 ft. There will be no dredging near the channel shoreline."

On July 7, 2020, the gas pipeline technician likewise closed One-Call ticket TX2067555147CA, classified as "3-Clear," remarking, "Cleared by mapping system and talking to [the Orion project engineer] Enterprise line 124 is 60 ft. to the south and will not be affected."

7.5. Temporary and Permanent Pipeline Marking

7.5.1. Temporary Markers

Following Enterprise's closure of the June 30, 2020, One-Call tickets, the Orion project engineer conferred with her supervisor, the project manager, who expressed concern about the potential close proximity of the dredge swing anchors to the pipelines.[99] The project manager confirmed that he and the Orion dredge superintendent became concerned about the need to place anchors outside (south) of the dredge template and near the pipelines.[100] The project manager directed the project engineer to follow-up with Enterprise and request the pipelines to be marked. As a result, the Orion project engineer notified the Enterprise gas pipeline

[99] Orion Group project engineer, p. 35.
[100] Orion Group project manager, p. 17 - 18.

technician that Orion planned to place swing anchors in the vicinity of the Enterprise pipeline and therefore requested an on-site meeting to discuss the project and mark the pipeline.

On July 15, 2020, the Orion project engineer emailed the Enterprise gas pipeline technician to confirm that Orion would provide a skiff and cane poles for marking the pipelines. The project engineer offered support to mark the pipeline with cane poles because the company typically uses them to mark pipelines and other features for avoidance. Accordingly, on July 16, 2020, the Enterprise gas and hazardous liquids pipeline technicians met the Orion project engineer and an Orion boat operator at the EPIC terminal job site.[101]

The Enterprise pipeline technicians observed that about half of the cane poles that had been used to mark pipeline TX219 in 2019 were still in place. However, the technicians decided to locate the pipeline using a line-locater instrument and add additional cane poles supplied to them by Orion to courtesy locate and mark the pipeline.[102] First, the Enterprise hazardous liquid pipeline technician used pin flags to mark onshore segments of the pipeline near the project. However, the Orion project engineer told NTSB investigators that she was not aware of any pin flags being placed onshore to mark the pipeline.[103] The group then boarded a skiff and used an electronic line locator to locate the portion of TX219 under water (Figure 17).

According to the Enterprise Products damage prevention program, use of electronic line locating equipment is required for courtesy locating, however, verifying the accuracy of the electronic line locator was not required. Because they were conducting a courtesy locate and not locating the pipeline in response to a One-Call ticket, the Enterprise pipeline technicians used their line locating equipment to only locate northern-most pipeline TX219.

The Enterprise gas pipeline technician told NTSB investigators that he just filled in the gap between remaining cane poles placed in 2019, placing the new cane poles about 5 feet channelward of pipeline TX219 to provide added buffer area.[104] The Enterprise Products hazardous liquid pipeline technician recalled that they placed five or six new cane poles about 10 feet channelward of the pipeline to create a buffer zone.[105]

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[101] Orion Group project manager, p. 32. Orion Group project engineer p. 40, 44.

[102] The pipeline technician had available two line location instruments: Radiodetection model RD8000 and RD8100 precision multifunction cable and pipe locators with depth and location accuracy of ±5 %. The technician connected a transmitter module to the nearest cathodic protection test station to impart an electrical signal onto the pipeline, which allowed him to pinpoint the location of the buried pipeline using a handheld wand device. Neither of the instruments were equipped with optional GPS data logging functionality. A "courtesy location" is the non-mandatory locating and marking of pipeline facilities where the planned excavation is greater than 50 feet but not more than 200 feet from the facility and not on a company right of way. Enterprise Products did not consider the placement of anchors to be excavation activity.

[103] Orion Group project engineer, p. 49.

[104] Enterprise Products gas pipeline technician, p. 19, 48-49, 55.

[105] Enterprise Products hazardous liquids pipeline technician, p. 23, 26.

Figure 17. Enterprise pipeline technician setting cane poles to mark pipeline TX219 in the vicinity of the accident, July 16, 2020, courtesy, The Orion Group.

The Orion Group project engineer told investigators that during cane pole installation the water was too shallow for the skiff to pass over the pipeline, which was visible in the water. She stated the old cane poles previously installed were very close to the pipeline, so they chose to place them about 20 feet apart on the outside of the pipeline that was furthest in the water, "just subjectively." Although Orion sometimes added flagging to cane poles, the poles used to mark these pipelines did not have any flags.[106]

During the meeting to mark the pipeline, the Enterprise gas pipeline technician told the Orion Group project engineer that any dredging activity within 12 feet of the pipeline would require that Enterprise technicians be onsite to monitor. He told NTSB investigators, "but on something like that, dredging with what they were dredging with, we'd have to turn that into encroachment being that close." Once the pipeline was located with cane poles, he asked the Orion Group project engineer if any anchors were going to be placed near the pipeline and she responded, "no."[107]

The Orion Group project engineer told NTSB investigators that she questioned the Enterprise pipeline technicians how far away the company should stay from the pipelines. The pipeline technicians responded, "if we stayed about 20 foot off, we would be good."[108]

The Enterprise hazardous liquids pipeline technician acknowledged having an agreement with the Orion Group project engineer that the anchor would not be placed within 20 feet of the

[106] Orion Group project engineer, p. 22-23.
[107] Enterprise Products gas pipeline technician, p. 32-33.
[108] Orion Group project engineer, p. 31.

cane poles. He said the marking provided for the 10-foot buffer zone plus the 20 feet standoff for anchoring. Also, during the July 16 meeting, the Orion Group project engineer continued to maintain that no dredging would occur within 60 feet of the shoreline.[109] However, the Enterprise Products gas pipeline technician had no recollection of a discussion that a 20-foot dredging standoff from the pipeline or cane poles would be acceptable.[110]

Some Orion Group crews remembered seeing that pink ribbons were affixed to the cane poles.[111]

On August 22, 2020, U.S. Coast Guard investigators collected photographs of the accident scene that show two cane poles east of the pipeline breach, and on the shore-side (south) of pipeline TX219 (Figure 18). However, one of the two cane poles had disappeared by the time Enterprise Products conducted a September 30, 2020, GPS survey of the temporary and permanent pipeline markers in this area. Investigators found no surviving temporary pipeline markers immediately adjacent to the breached pipeline location (Figure 19).

On September 30, 2020, Enterprise Products contractor SAM conducted a post-accident temporary and permanent pipeline marker survey (Figure 20). The survey identified one surviving cane pole, labeled GPS 2289, which was located between the 10-inch abandoned non-Enterprise pipeline and pipeline TX219.

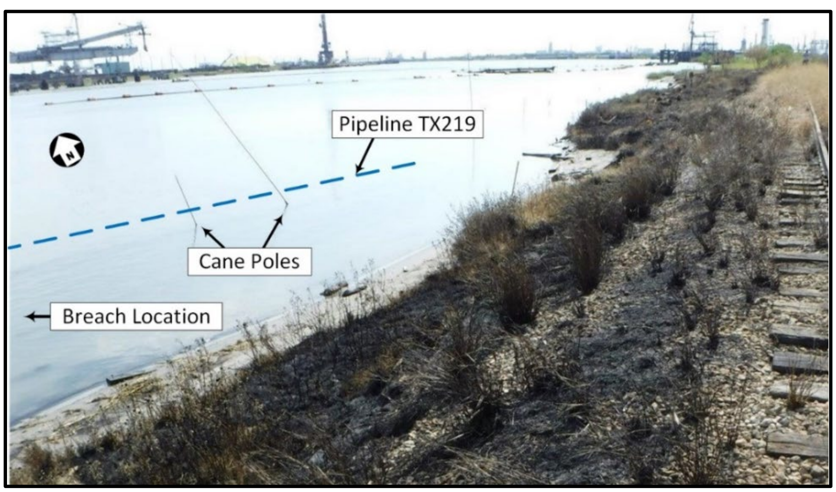

Figure 18. Annotated August 22, 2020 U.S. Coast Guard photograph of the accident scene showing two cane poles that had been placed on the shore-side of pipeline TX219. The right cane pole was identified as GPS 2289 in the subsequent Enterprise Products GPS survey of pipeline markers. The

[109] Enterprise Products hazardous liquids pipeline technician, p. 25-26.
[110] Enterprise Products gas pipeline technician, p. 62-63.
[111] NTSB interview of Orion Group deckhand, August 31, 2020, p. 30 and NTSB interview of Orion Group tender operator, August 31, 2020, p. 35. According to the American Public Works Association uniform color code for temporary marking, pink flagging would indicate a temporary survey marking.

breached pipe location is left of this image. The approximate location of TX219 is indicated by the dashed line.

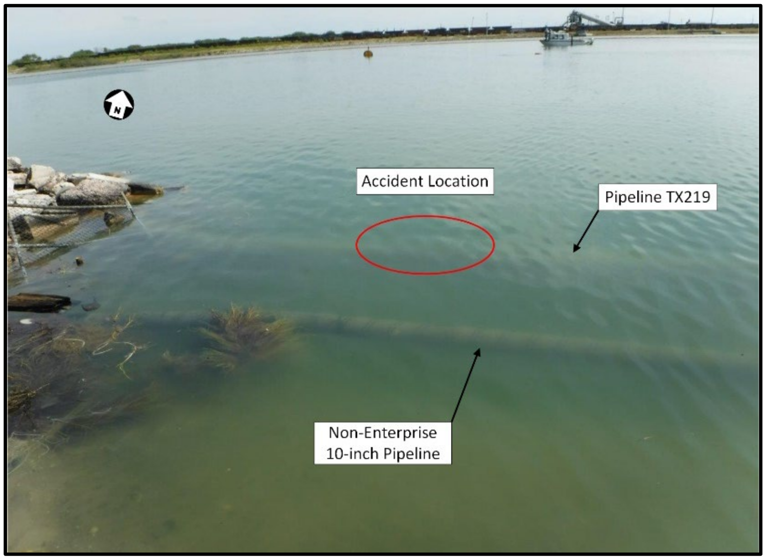

Figure 19. Approximate accident location showing two pipelines visible beneath the water surface. The furthest channelward is pipeline TX219. Closer to shore is a non-Enterprise Products abandoned 10-inch pipeline. There were no surviving temporary pipeline markers at the breached pipeline location. August 22, 2020, courtesy U.S. Coast Guard.

Figure 20. Post-accident September 30, 2020, Enterprise Products pipeline TX219 KML, temporary and permanent pipeline marker survey locations, and accident location projected on Maxar Technologies, Google Earth imagery of January 31, 2020. Cane pole GPS 2289 was located between the 10-inch non-Enterprise pipeline, which is partially visible as a dark line parallel to pipeline TX219 (green line).

Prior to recovering the damaged pipeline segment, Enterprise marked pipeline TX219 with temporary markers that consisted of uniform-height PVC poles with yellow flagging tape affixed (Figure 21). Divers attached a red marker buoy to the pipeline at the location where it was damaged.

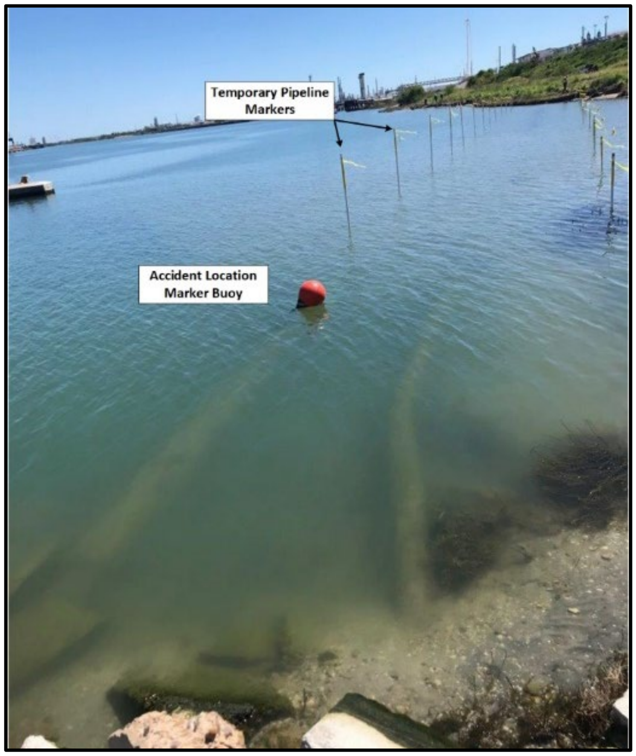

Figure 21. Temporary PVC pole pipeline marking for post-accident pipeline evidence recovery operations. The accident location is marked with a red buoy that divers affixed to pipeline TX219 where it was damaged. Courtesy, Enterprise Products, October 1, 2020.

7.5.2. Permanent Markers

Post-accident inspections and surveys found that all permanent pipeline markers in the vicinity of the accident scene were lying flat on the ground (Figure 22). On September 30, 2020, Enterprise conducted a pipeline marker survey that found four downed permanent markers, described as follows:

- GPS 2279-2280, downed and located onshore about 80 feet west of the breached pipe, the metal post was thermally damaged, and the signage was obliterated.
- GPS 2281-2282, downed and located onshore among riprap, about 22 feet west of the breached pipe, the signage was legible.
- GPS 2283-2284, downed and located in the water near shore, about 240 feet east of the breached pipe, the signage was covered with marine growth and not legible.

- GPS 2285 – 2286, downed and located in the water near shore, about 453 feet east of the breached pipe, the signage was covered with marine growth but still legible.

Title 49 CFR 195.410 requires pipeline operators to maintain line markers over buried pipelines. The marker must state at least the following on a background of sharply contrasting color:

> *The word "Warning," "Caution," or "Danger" followed by the words "Petroleum (or the name of the hazardous liquid transported) Pipeline."*

The marker must also provide the name of the operator and a telephone number where the operator may be reached at all times.

During the July 16, 2020 meeting with Enterprise Products pipeline technicians to mark the pipeline with cane poles, the Orion project engineer observed one yellow pipeline marker on land at the western point of the waterway exposure where pipeline TX219 transitioned from the ship channel onto land.[112]

The downed permanent pipeline marker nearest and west of the accident location is shown in Figure 22.

Figure 22. Downed permanent pipeline marker (GPS 2281-2282) near the accident location, September 14, 2020, U.S. Coast Guard photo.

[112] Orion Group project engineer, p. 49.

7.6. Dredging Crew Awareness of Pipeline Hazards

The June 26, 2020, Orion Group site-specific safety plan for the Epic Dock dredging project stated that it promoted communication between Orion's departments to ensure that safety and health protection was integrated throughout the course of the project. Although the safety risks associated with dredging near the pipeline were not specifically addressed by the plan, it did reference general processes for hazard prevention and control, such as:

- Daily and weekly site visits by Orion's safety department to ensure operations followed company policy. Any discrepancies were supposed to be brought to the foreman's attention and corrected.
- Daily safety meetings held by supervisors and foremen to discuss scheduling and planning.
- Job safety analyses (JSA), a component of safety meetings, were intended to ensure hazard awareness and that employees were trained for specific tasks to which they may be assigned. The plan stated that a JSA form was to be completed each day for the tasks to be performed.[113]
- Weekly safety meetings held by each foreman or other person in charge. Topics were supposed to be chosen that were relevant and unique to the industry.
- The Orion Group Hazard Control Reporting and Observation Program, which was intended to supplement the JSA. Employees were provided an IPAD application that allowed them to report behavior-based safety observations to the Orion safety department, as well as stop work and near miss occurrences. The program also provided for weekly "hazard hunts," wherein employees were supposed to walk the worksite looking for hazardous conditions and report findings to foremen.

Available Orion Group records for daily safety meetings the dredge crew held between August 16 and 18, 2020, documented discussions about dehydration, working from suspended platforms, COVID-19 safe work practices, in-situ burning for mitigating oil spills, use of hand tools (in Spanish), stretching and flexing, avoidance of shortcuts that lead to safety infractions, and daily safety checklist for job hazard analysis.

The daily JSA, or job hazard analysis, forms for the period August 1, through August 19, 2020, had identical content. None of the JSAs mentioned working near the propane pipeline or required clearance from the Enterprise pipelines.

The Orion Group director of health, safety and environment told NTSB investigators that pipeline hazards were not included in Orion Group's EPIC Dock site-specific health and safety plan because the pipelines were not located within the dredging scope of work. He further said that although Orion employed 5 health and safety professionals, no health and safety manager

[113] The written JSA form is titled "Job Hazard Analysis."

had been assigned to oversee daily activities at the EPIC Dock project because the client did not require it and there were not enough personnel to cover every ongoing project.[114]

The Orion Group regional health safety and environment manager, who was involved in the development and implementation of site-specific safety plan for the *Waymon Boyd,* did not include information about the Enterprise pipelines in the plan. The regional health safety and environment manager told NTSB investigators that he was not aware that pipelines were present near the job site until after the accident occurred.[115]

7.6.1. Project Engineer

On July 20, 2020, after accompanying the Enterprise pipeline technicians to mark the pipeline locations with cane poles, the project engineer emailed the dredge *Waymon Boyd*,[116] the project manager, and the two dredging superintendents informing them:

> *There are 2 pipelines near the shoreline at EPIC. They are marked with cane poles and we've been asked to stay 20' away from them. Please keep in mind when working in the area and placing swing anchors.*

The Orion Group project engineer followed up this email communication with telephone calls to the dredge superintendents to ensure that they had received the message and were aware of the pipeline location and the cane pole marking. She stressed that dredging operations needed to stay 20-feet away from the cane poles.[117]

7.6.2. Survey Superintendent

Before the accident, the Orion Group survey superintendent was aware that pipelines were running along the bank of the channel "in the rocks" and "kind of out of the way." He knew from the Schneider Engineering drawings (Figure 15) the pipelines were outside of the dredge project boundaries and did not consider the pipelines, nor was he asked to include them, when developing the dredging template data for the DREDGEPACK®. However, he told NTSB investigators that had GPS coordinates for the pipeline been provided to Orion in response to the One-Call, he would have been able to include it in the DREDGEPACK® template.

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[114] Orion Group director of health, safety, and environment, p. 32-33. Although at the time of the accident Orion employed 17 health and safety professionals company-wide, its dredging division had a regional manager, 4 safety professionals, and an office assistant.

[115] NTSB interview of the Orion Group regional health, safety, and environment manager, April 29, 2021.

[116] Emails addressed to the dredge *Waymon Boyd* are received by the captain and the deck captain.

[117] Orion Group project manager, p. 19, 31-32.

Although he believed the pipelines were outside of the dredge template, on the day of the accident the Orion survey superintendent reviewed the file to reexamine their location in relation to the dredge template. On September 19, 2020, Orion survey crews conducted a post-accident GPS survey to verify the pipeline location and separation distance outside of the template. According to the survey superintendent, this survey found TX219 was 6 ½ to 7 feet from the template at its closest point (see Figure 24).[118]

7.6.3. Project Manager

The Orion Group project manager told investigators that the pipeline was located near, but outside of the dredge template. He explained that dredge template consisted of the area inside the trapezoidal box as shown on the Schneider Engineering and Consulting, EPIC Marine Terminal Dredging Construction Plans dated June 23, 2020 (see Figures 15 and 16). The slope leading from the trapezoidal East Dock berthing area box south toward the shoreline, which was required to be cut back to achieve a 2.5:1 (horizontal:vertical) grade, was also part of the dredge template.[119]

7.6.4. Dredge Superintendent 1

The Orion Group dredge superintendent 1 first learned about the presence of the Enterprise pipeline that ran near the shoreline during a May 3, 2019, preconstruction meeting with EPIC officials. During the preconstruction meeting he attended with the Orion Group project manager, surveyor, and dredge superintendent 2, they walked close to the pipeline and observed that it was exposed below the water surface. Also, during the 2019 preconstruction meeting, EPIC officials told the dredge superintendent 1 that the Enterprise pipeline was between 5 and 10 feet outside of the top of the dredge slope, and so his only concern was the placement of swing anchors near the pipe since he believed dredging was not supposed to occur there. He observed that the pipeline location was marked with cane poles before commencing the 2019 phase 1 dredging operations.[120]

Before the second phase of dredging began, the project engineer informed dredge superintendent 1 that cane poles had been installed to mark the pipeline. He later viewed the cane poles and then told the dredge captain to avoid getting close to the pipeline with the swing anchors. The dredge superintendent 1 was last onboard the *Waymon Boyd* on Tuesday, August 18, 2020, three days before the accident. On that occasion, he spoke to the deck captain and leverman about the need to be mindful of the Enterprise pipeline while repositioning the dredge

[118] Orion Group surveyor, p. 20-23, 26-27.
[119] NTSB interview of Orion Group project manager, September 11, 2020, p.16, 50.
[120]Orion Group dredge superintendent 1, p. 30-33, 35, 48.

in that area. He reminded them the pipeline was marked with cane poles and to be particularly careful about placing swing anchors near the pipeline.[121]

7.6.5. Dredge Superintendent 2

The Orion Group dredge superintendent 2 had been aware of the pipelines along the shoreline since the first phase of the dredging project. He did not recall receiving any updated information about the pipelines when the second phase of dredging was initiated. The last time he was on scene prior to the accident was mid-July to review the dredge slurry discharge pipeline route. While he was aware the Orion project engineer met with Enterprise Products following a One-Call notification, he did not recall receiving any follow up communication about the proximity of the pipeline to the dredging project. He also did not recall speaking to the leverman about the pipelines and normally only interacted with the dredge captain and the deck captain. He expected that the dredge captain or deck captain would have informed the leverman about safety matters relating to the pipeline.[122]

7.6.6. Deck Captain

The Orion Group deck captain was not present on the dredge at the time of the accident. He worked a ten-day period on the dredge until Thursday, August 20 at noon, the day before the accident. He was aware of the location of the Enterprise pipelines because they had been marked with cane poles that were visible from the dredge. In addition, whenever the tide was low the pipelines were visibly exposed out of the water. However, he knew the pipelines were located outside of the dredging template because they were not displayed on the leverman's computer screen and he therefore was not concerned about the possibility of pipelines becoming damaged. The deck captain acknowledged receipt of the July 20, 2020, email from the project engineer instructing crews to stay 20 feet away from the pipelines.[123]

The deck captain believed the leverman was also aware of the presence of pipelines near the project template because they discussed avoiding the pipeline during each of their morning conversations. They were mostly concerned about anchor barge movements in that area during high tide but concluded the anchor barges would not be able to get close to the pipeline without first running aground.[124]

[121] Orion Group dredge superintendent 1, p. 31, 34-35.
[122] NTSB interview of Orion Group dredge superintendent 2, October 14, 2020, p. 20, 45-47, 67.
[123] Orion Group deck captain, p.16, 23-27.
[124] Orion Group deck captain, p. 27.

7.6.7. Dredge Captain

The dredge captain recalled that in all previous projects he worked on where dredging occurred near pipelines, the pipeline crossed perpendicular to the shipping channel. For those previous projects, the pipelines were marked with signage and the location of the pipelines were displayed on the DREDGEPACK® screen. The dredge captain did not have any previous experience dredging near pipelines that ran parallel to the shoreline as was the case in the EPIC East Dock project. However, for the EPIC project he understood the dredging activity was supposed to remain 25 feet away from the pipeline.[125]

The dredge captain knew that safety data sheets for material in the pipelines were contained in a book stored on the dredge, however he did not have any communications with Enterprise about the nature of hazardous liquids transported in the pipeline.[126]

8. <u>Pipeline Operations on the Day of the Accident</u>

Enterprise pipeline flow recordings for pipeline TX219 indicated that at 0426 on the day of the accident, propane flow initiated from Flint Hills Resources for batch number 75 into the pipeline. The pipeline pressure increased from its no flow state of about 200 psig and maintained a pressure of about 257 psig to 265 psig for the duration of the batch transport. The total batch volume transported in the pipeline was about 1,529 barrels. SCADA system pressure indications near the time of the accident showed that between 0630 and 0802, the pipeline pressure remained unchanged at 257 psig.

Refer to Appendix A for more information about the pipeline operations chronology of events on the day of the accident.

8.1. Enterprise Products Control Center and Corpus Christi Facility Actions

As the batch transfer was nearing completion, at 0802:49, the SCADA system alerted the pipeline controller with an annunciation of a low-pressure alarm indicating the Viola Meter Station pipeline pressure had dropped to 156 psig (see Figure 13).[127] The pipeline controller acknowledged the alarm in the SCADA system at 0802:59. The pipeline controller investigated the alarm and formulated a plan to contact a local pipeline technician to respond.

At the downstream end of the pipeline system, Origin Station meter 345 registered propane

[125] Orion Group dredge captain, p.25, 42.

[126] Orion Group dredge captain, p. 119.

[127] The Enterprise Products SCADA servers receive time validation from two Enterprise routers: a primary and a backup router. Both routers' primary timekeeping source is 129.6.15.28 (time-a-g.nist.gov). There is not a periodic re-sync that occurs. Instead, a series of ongoing packet exchanges occur, which are used to keep the clocks synchronized.

flow trending downward at 0803. The SCADA system annunciated an alarm at 0803:40 indicating no flow at meter 345. The pipeline controller acknowledged this alarm at 0803:46.

At 0805:19, the SCADA system then annunciated a subsequent low-pressure alarm indicating the line pressure at Viola Meter Station had dropped further to 149 psig. Also, at 0805, the pipeline controller telephoned Flint Hills Resources operator, who reported the refinery had finished transferring the propane batch to Line TX219.[128] At 0805, Flint Hills Resources shut down its propane delivery pump.

Also, at 0805, the Flint Hills Resources to Viola Meter Station control valve automatically began to close. At 0807, Viola Station flow meter 1004 indicated propane entering the pipeline from the refinery had stopped. The pipeline controller did not know whether this control valve closure was prompted by completion of the batch transfer or by the low-pressure trend on the pipeline. Between the first indication of a pressure drop at 0802:49 and closure of the control valve, about 19 barrels of propane were introduced into the pipeline along with the existing line pack. The pipeline controller logged the pressure anomaly and then acknowledged the second SCADA alarm at 0809:59.[129]

After noting SCADA low pressure states for the Viola Station skid outlet and the Viola Station incoming pressure to TX219, at 0809, the pipeline controller telephoned the Enterprise Products Corpus Christi facilities pipeline technician 3 to request an investigation. The pipeline controller informed pipeline technician 3 that the SCADA screen indicated a sudden drop in pressure at flow meter #1004, and he directed him to respond to Viola Station to determine if the pressure reading was accurate. Pipeline technician 3 told the pipeline controller that an explosion occurred and that he observed fire on the Corpus Christi Ship Channel from his location at Origin Station. The pipeline controller notified the pipeline control center shift supervisor and control manager of the on-going situation.

At 0815, to eliminate the possibility of backflow in TX219, the pipeline controller telephoned the Origin Station pipeline operator and instructed him to close the manual valve at Meter 345 to isolate TX219 from pipeline M4-6 (Figure 19). The pipeline operator walked to the meter and completed shutting the valve at about 0830, isolating Line TX219 from propane storage tanks at Origin Station.[130]

At 0831, upon his arrival at the Viola Station, pipeline technician 3 contacted the pipeline controller and reported the pipeline pressure downstream of the control valve was at that time

[128] Enterprise Products pipeline controller, p. 67.
[129] Enterprise Products pipeline controller, p. 41–42, 53.
[130] NTSB interview of Enterprise Products pipeline operator, October 20, 2020, p.12-14.

131 psig. The two agreed that motor operated valves should be closed to add redundant isolation to the control valve.

At 0841:25, the pipeline controller issued a command through the SCADA to remotely close valve MOV 20. By 0842:19 the SCADA system reported the valve had successfully closed.

At 0843:49, the pipeline controller issued a command to remotely close Viola Meter Station valve SDV 25. At 0845:19 the SCADA system reported the valve had successfully closed. Pipeline technician 3 confirmed both valves had closed tightly. Also, about 0843, pipeline technician 3 advised the pipeline controller that the Flint Hills Resources valve site had been secured such that no additional propane could enter Viola Station.

At 0851, pipeline technician 3 traveled to the Cantwell Station downstream on the pipeline, where he assisted the pipeline operator to secure two additional valves for supplemental security of Line TX219, double blocking line M4-6 between Cantwell Station from Origin Station. At 0905, the pipeline operator contacted the pipeline controller to inform him of the Cantwell Station valve closures.

Between 0919 and 1003, pipeline technician 3 monitored continued pressure reduction on the pipeline from the Cantwell Station and reported it to the Enterprise Products safety representative who was providing the data to emergency response officials at the scene of the pipeline accident.

At 0947, the Port of Corpus Christi notified the Pipeline Control Center that a dredging operation had struck a pipeline and there was a fire. At 0953, local Enterprise operations personnel confirmed that line TX 219 was involved in the incident.

At 1052, Enterprise filed National Response Center (NRC) report number 1285164, reporting the incident at 5700 Upriver Road, in Corpus Christi, Texas.[131] Enterprise reported that a fire was seen on closed circuit television at 0822 on August 21, 2020. Enterprise reported that at 0954, it was determined that an Enterprise Products pipeline was involved in the incident. Enterprise reported that a third party was dredging in the Corpus Christi Ship Channel and struck their 16-inch steel underwater propane transmission pipeline.

By 1135, pipeline technician 3 and the Origin Station pipeline operator locked out and tagged out valves that were closed at Cantwell Station, Flint Hills Resources, and Viola Station. He

[131] The National Response Center (NRC) is an emergency call center staffed by the U.S. Coast Guard, which fields initial reports for pollution and railroad incidents and forwards that information to appropriate federal and state agencies for response. Title 49 CFR 195.52 requires the pipeline operator to file immediate notice to the National Response Center no later than one hour after confirmed discovery of certain incidents involving death, injury, fire, explosion, or pollution.

also deenergized and placed a lockout/tagout on the electrical breaker for motor operated shut down valve SDV 25.

A summary of Enterprise Products' actions to isolate the pipeline is provided in Figure 23.

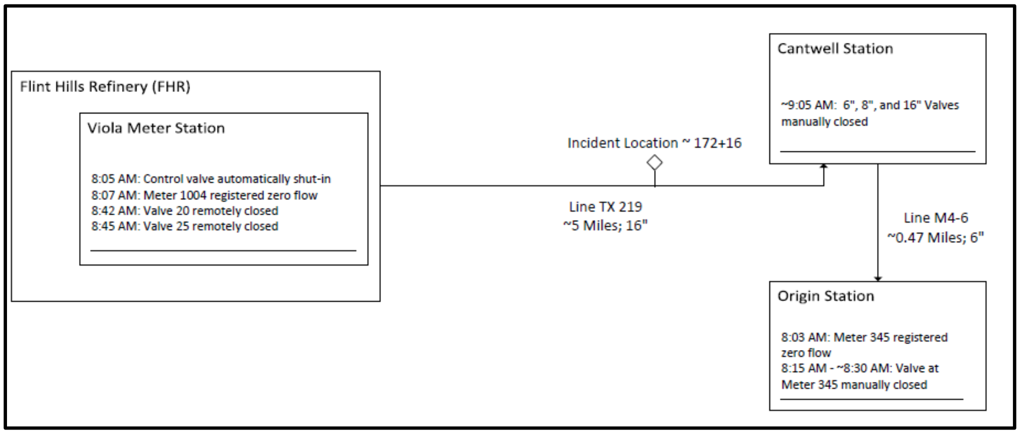

Figure 23. Summary of Enterprise Products actions to isolate pipeline TX219 on August 21, 2020, following the accident.

At 1213, the Coast Guard Command Center filed NRC report number 1285180 describing the incident as "the dredge *Waymon Boyd* struck a gas pipe near the EPIC Dock near Inner Harbor, Corpus Christi, Texas." The report stated that the vessel and dock were engulfed in flames, and that there were 10 burn victims, of which 6 were unaccounted for at that time. The NRC report noted that the ruptured Enterprise Products pipeline had been secured. The report noted that Coast Guard Sector Corpus Christi activated an incident management team to assess threats to the port.

8.2. Post-Accident Drug and Alcohol Testing

In accordance with 49 CFR 199.105(b), on August 21, 2020, Enterprise Products subjected the pipeline controller to post-accident drug testing under the Substance Abuse and Mental Health Services Administration (SAMHSA) guidelines for five commonly abused drugs. For further information, see the NTSB Medical Factual Report contained in the docket for this investigation.

9. Properties of Non-odorized Propane

Pipeline TX219 was used to transport grade HD-5 non-odorized propane, which is a highly volatile liquefied gas that forms a vapor cloud when released to the atmosphere.[132] Propane is

[132] HD-5 propane is the most widely sold and distributed grade of propane in the U.S. market. It may contain up to 5% propylene and a minimum of 90% propane. Other gases that constitute the remainder are iso-butane, butane,

a colorless and tasteless gas at normal temperature and pressure. Transported under pressure, liquefied propane is 270 times more compact as a liquid than as a gas, thus making it economical to store and transport as a liquid. The specific gravity is about 0.504; vapor pressure is 127 psig at 70º F; the vapor is 1.5-times as heavy as air, and it can collect in low areas that are without sufficient ventilation. Propane gas can collect in a confined space and create an explosive atmosphere, as well as threaten life by displacing breathable air. The flash point is -155 ºF (closed cup), its lower explosive limit (LEL) is 2.1% concentration in air, the upper explosive limit (UEL) 9.5 % concentration in air, giving propane a narrow range of flammability when compared to other petroleum products. Flashback along a vapor trail is possible. Under fire conditions, hazardous decomposition products include fumes, smoke, and carbon monoxide. Propane is a simple asphyxiant with slight anesthetic properties. The NIOSH immediately dangerous to life and health (IDLH) concentration is 10% of the LEL (2,100 ppm). Contact with liquid can cause frostbite.

Propane has no odor warning properties, thus at the point of delivery an odorant (ethyl mercaptan) is added to provide a strong unpleasant odor to aid in the detection of leaks. Federal regulations do not require the odorization of materials transported in hazardous liquid pipelines. The National Fire Protection Association (NFPA) liquefied petroleum gas code states that all liquefied petroleum gases shall be odorized prior to being loaded into a railcar or cargo tank motor vehicle by the addition of a warning agent of such character that the gases are detectable by a distinct odor to a concentration in air of not over one-fifth the lower limit of flammability.[133] Therefore, after being transported through Enterprise's transmission pipelines, odorant is added to the propane at truck and rail loading terminals, prior to being distributed to downstream customers.

10. Propane Volume Released in the Accident

Enterprise calculated the amount of propane released in this accident as follows:

A + B – C = 6,015 +19 – 10 = 6,024 barrels (253,008 liquid gallons)

Whereas,
A = Pipeline linepack (inventory) from static conditions prior to incident, 6,015 bbl.
B = Propane entering the pipeline at meter 1004A at Viola Station between 0802 and 0806 was 19 bbl.
C = Less propane exiting the pipeline at meter 345 at Origin Station between 0802 and 0806 was 10 bbl.

and methane. As described in Part 195.2, a highly volatile liquid means a hazardous liquid that will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 40 psia at 100 °F.

[133] NFPA 58 Liquefied Petroleum Gas Code 2020, Section 4.2, (Quincy, MA, National Fire Protection Association, 2020).

11. Postaccident Pipeline Evidence Recovery

11.1. Damaged Pipeline Location Surveys

On September 19, 2020, the Orion Group survey superintendent and surveyor conducted a single beam hydrographic survey to focus on the scour under the breached pipeline. The survey used sonar at 1-foot intervals to detail the scour. In addition, the surveyor obtained GPS coordinates for the top of the breached pipeline, touching the aluminum foot of a real-time kinematic (RTK) pole to the concrete-coated portion of the pipeline (Figures 24 and 25).[134]

The Orion Group provided NTSB investigators its most recent pre-accident single beam dredge survey conducted on August 17, 2020, along with its September 19, 2020 pipeline GPS survey data superimposed on the drawings (Figure 24). This figure also shows Orion Group's post-accident September 19, 2020 single beam survey of the cross-section station location closest to the area of the pipeline breach. The GPS coordinates were collected with a calibrated sounder/transducer with bar check method.[135] Technicians accessed the pipeline from a boat.

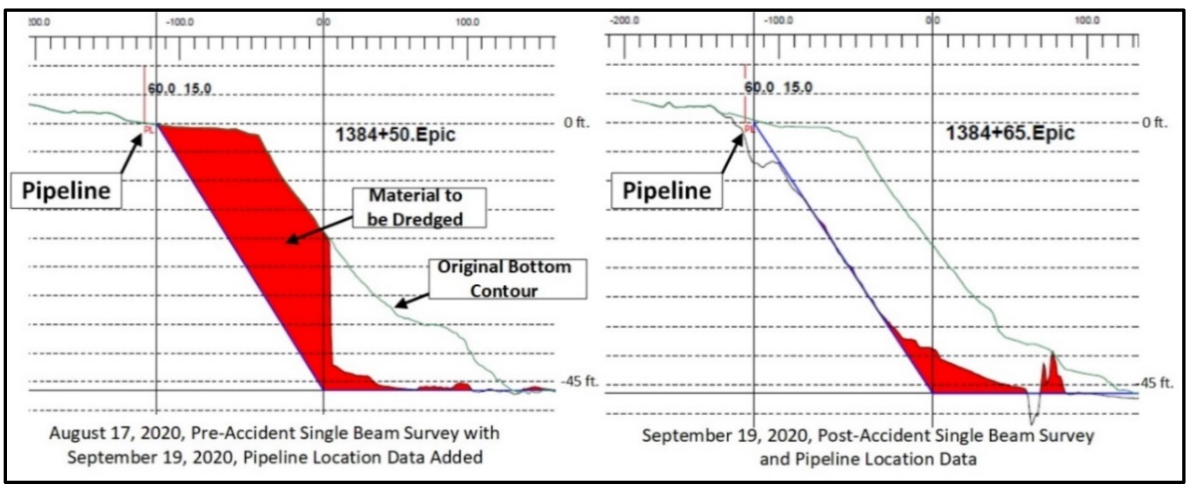

Figure 24. Orion Group single beam survey cross sections near the damaged pipeline. The location of the pipeline as determined by Orion's September 19, 2020 GPS survey was added to the pre-accident scan taken on August 17, 2020 (left). The post-accident scan closest to the pipeline is shown on the right.

[134] Real-time kinematic receivers are a satellite positioning tool that enhances the precision of positioning data to achieve sub-foot accuracy. Survey-grade real-time kinematic receivers allow accuracy to 1-2 cm (0.1 ft).

[135] The survey instruments used included a Dell laptop computer, Odom Hydrotrac II sounder, Odom 200 kHz transducer, Trimble SPS361 differential GPS receiver with OmniSTAR corrections.

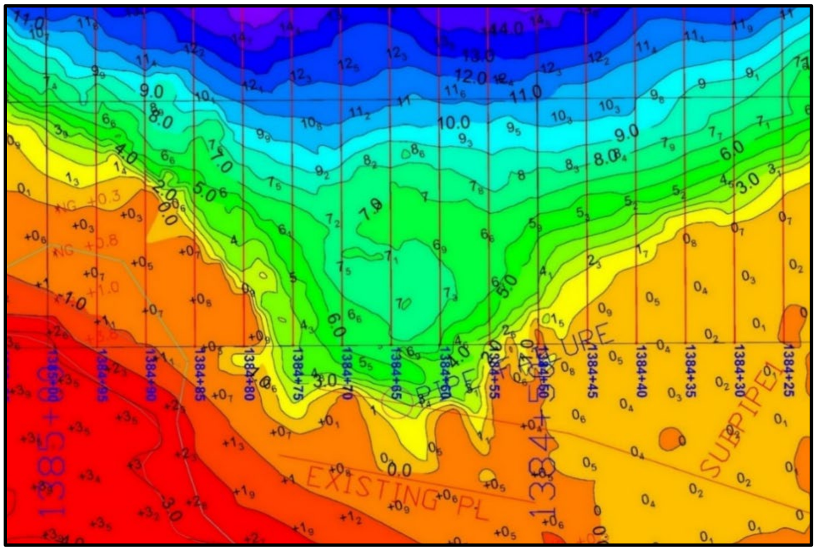

Figure 25. Excerpt of September 19, 2020, Orion Marine Group post-accident plan-view single beam hydrographic survey with dredge template overlay. The surveyed location of the breached pipeline TX219 (orange line) and the location of the "pipe failure" (orange circle) are shown. Coordinate system NAD83, Texas State Plane Grid, South Zone, U.S. Survey Feet.

On October 5, 2020, Enterprise contractor SAM collected GPS location data for the east and west pipe cuts that were made to recover a 14 ft. 4 in. segment of the damaged pipeline.[136] The damaged pipe segment and the location of the accident, measured to be 2 ft. 8 in. east of girth weld 444000, are annotated over a HYPACK 2018 view shown in Figure 26.[137]

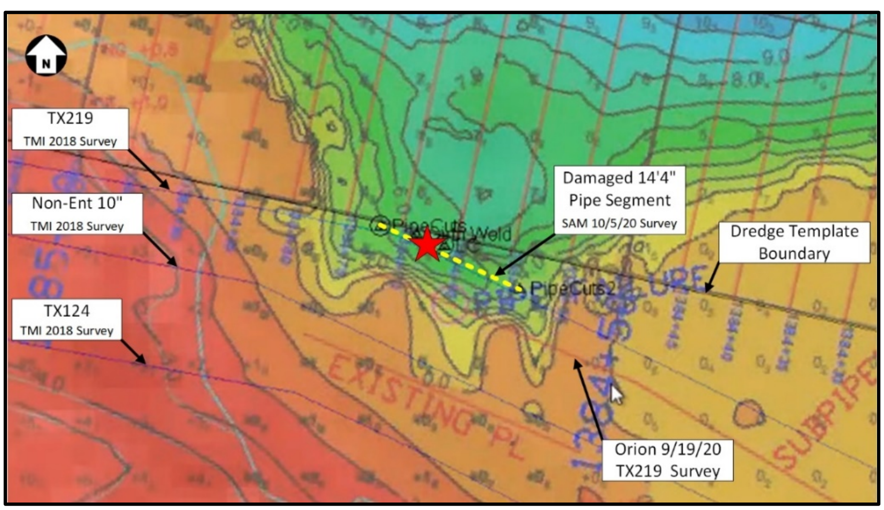

Figure 26. Orion Group September 19, 2020, post-accident single beam hydrographic survey, dredge template, and pipeline location base image overlaid onto the TMI Solutions LLC December 28, 2018, pipeline surveys using HYPACK 2018. The SAM survey of the pipe cut locations for the recovered

[136] The survey points were collected using a Trimble R10 GNSS receiver, verified against a control point to at least ±0.1-foot. Survey data was delivered in coordinated system NAD1983 ("Conus") State Plane Zone, Texas South 4205.

[137] Girth weld 444000 coordinates were determined from the 2016 inline inspection data.

damaged pipeline segment on October 5, 2020 is depicted with the dashed yellow line and the approximate accident location is indicated by the red star. Dredge template station lines are 5-foot intervals. Image overlay courtesy HYPACK, a Xylem brand with NTSB annotations.

NTSB investigators also measured the distance in the HYPACK module between pipeline TX219 at the accident location as determined in the TMI LLC December 28, 2018 survey to the south border of the dredge template, finding a separation of 1.90 feet (Figure 27). Similarly, the measured distance from the point of damage (point "LC" in Figure 27) to the dredge template as determined from the 2016 ILI location data for the pipeline was 0.98 ft.

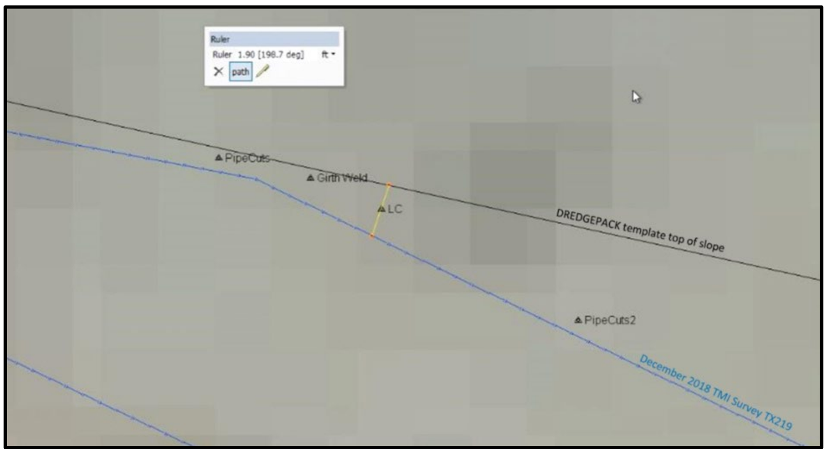

Figure 27. Distance measurement in the HYPACK 2018 module from the TMI Solutions LLC, December 28, 2018 pipeline TX219 survey location (blue line) to the edge of the Orion Group dredge template (black line) at the point of damage to the pipeline, or "LC" (location of contact 2'8" east of the girth weld), showing 1.90 feet of separation. The distance measured from point "LC" to the dredge template line was 0.98 feet. Courtesy HYPACK, a Xylem brand.

Post-accident surveys and pre-accident inline inspections also also found a difference in the reported location of TX219 and GIS data Enterprise maintained for the line as determined by the 2011 Rosen Group ILI location data. Figure 28 shows a Google Earth view, approximating the location of the offset between the Rosen 2011 ILI location data and the SAM post-accident October 5, 2020 pipeline cut survey, measured to about 8.2 feet near the accident location using Google Earth tools.[138]

[138] On March 3, 2020, Enterprise provided the Rosen Group 2011 ILI location data to PHMSA's National Pipeline Mapping System. PHMSA publication *Standards for Pipeline, Liquefied Natural Gas, and Breakout Tank Farm Operators Submissions* (Washington DC, Pipeline and Hazardous Materials Safety Administration, 2017), provides location accuracy standards for submissions to the National Pipeline Mapping System. PHMSAs mapping data is a public awareness tool for initially obtaining general transmission pipeline location data in a given area and is not provided as a substitute for contacting a One-Call damage prevention system before excavating.

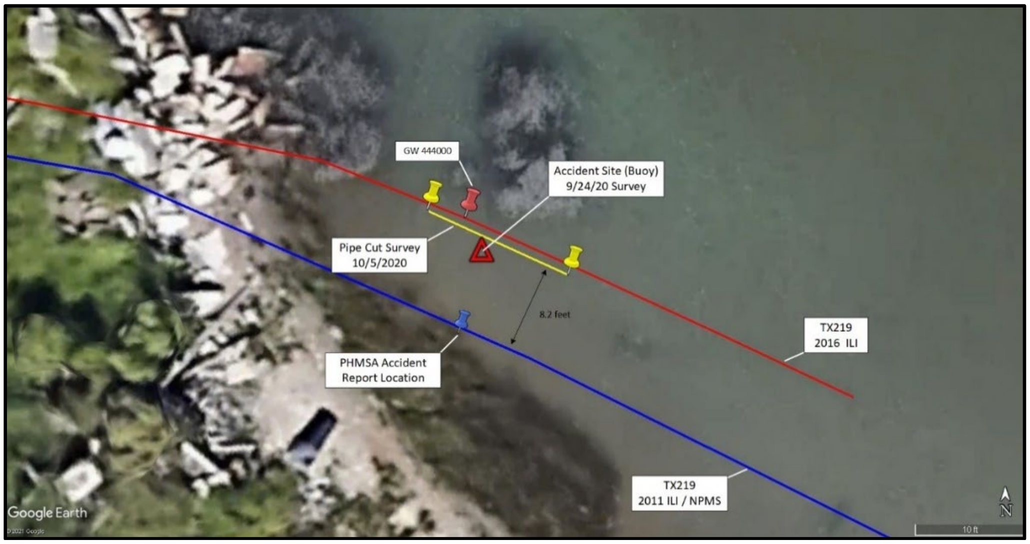

Figure 28. Annotated Google Earth base image showing approximate location data for pipeline TX219, including from south to north, the Rosen Group 2011 ILI inline inspection GPS location coordinates file (blue line), the SAM October 5, 2020 evidence recovery pipe cut survey (yellow markers), and the Rosen Group 2016 inline inspection GPS location coordinates (red line). The accident site as determined by a September 24, 2020 SAM survey of a buoy marker is indicated by a red triangle. The base imagery date is January 31, 2020.

The SAM pipe cut survey, depicted as the yellow line in Figure 28, was collected in accordance with NTSB evidence recovery protocols discussed in Section 11.2.

11.2. Damaged Pipeline Evidence Recovery

NTSB investigators and investigative parties developed protocol for the recovery, crating, and shipping of the damaged pipeline segment, which consisted of a 14-foot 4-inch segment of pipeline TX219 submerged underwater at the accident scene (Figures 29 and 30). In addition, Enterprise developed a procedure for lifting, preserving, inspecting, documenting, crating, and transporting pipeline evidence to NTSB laboratory facilities.

On October 5, 2020, Enterprise Products and its contractor, Dean Equipment LLC, rigged the damaged pipeline segment from the accident scene and placed it on a material barge for transport to a Corpus Christi shipyard in accordance with the evidence recovery protocol and Enterprise procedures. During the removal process, two 1-foot-long fractured pieces of concrete sleeving fell from the west end of the pipe segment and were collected along with the pipeline evidence. Enterprise contractors photographed and video documented the evidence recovery process. From there, the pipe segment was rigged into a transportation crate and transported to a secure warehouse for temporary storage.[139]

[139] The secure warehouse was located at H&E Equipment Services, 7809 IH37 Access Road, Corpus Christi, Texas.

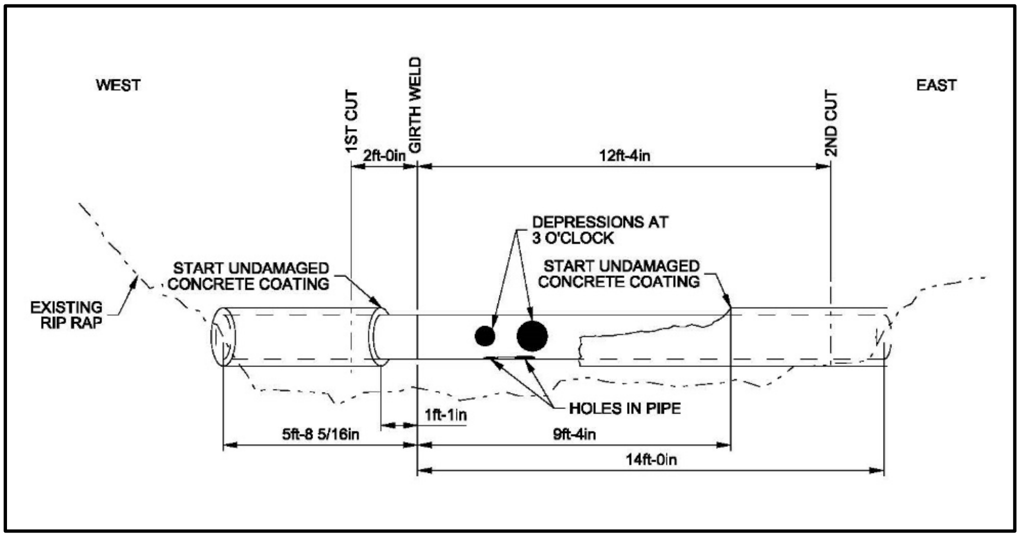

Figure 29. Drawing of the damaged pipeline segment and agreed upon location for cuts. Courtesy, Enterprise Products.

Figure 30. Photograph facing south toward the shoreline as Enterprise Products crews and contractors rigged the extracted damaged pipeline segment from the accident location, October 5, 2020. Courtesy, Enterprise Products.

On October 6, 2020, investigative parties were provided an opportunity to examine the damaged pipeline segment at the secure warehouse. Enterprise contractor Stress Engineering collected and distributed high-resolution photographs of the pipe.[140]

[140] Participating parties included Enterprise Products, U.S. Coast Guard, Railroad Commission of Texas, and Orion Group. In addition, Gateway Logistics and Stress Engineering were on site to provide package handling and photographic services.

On October 7, 2020, Enterprise and its contractors collected 3-D scanning data. Following this exercise, they crated the damaged pipe for shipment to the NTSB Materials Laboratory in Washington, D.C. A second, smaller crate was used to transport two pieces of concrete pipeline coating that separated from the west side of the pipe segment during the removal process.

Also, on October 7, 2020, Gateway Logistics Group transported the pipeline evidence to NTSB Headquarters in Washington D.C. NTSB received the evidence shipment on October 9, 2020 (Figure 31). The NTSB evidence control number was: DCA20FM026-PLO-001, described as "14ft.4in section of pipeline TX219, 16-inch diameter steel with concrete coating."

Figure 31. Gateway Logistics Group preparing to transport crated pipeline TX219 evidence to NTSB Headquarters, October 7, 2020, courtesy Stress Engineering.

11.3. Cutterhead Teeth

On September 16, 2020, NTSB investigators and investigative parties developed protocol for the recovery of the dredge cutterhead and for shipping of selected cutterhead teeth to the NTSB Materials Laboratory for examination. On September 17, 2020, Orion Group and its contractors salvaged the cutterhead from the sunken dredge.

NTSB investigators randomly selected Blade "D" of the five blade cutterhead for measuring the radial distance between each tooth relative to the center (longitudinal axis) of the cutterhead. U.S. Coast Guard investigators measured the distances between the center of the cutter head and the inboard and outboard edges of each tooth. The geometry and condition of the cutterhead was further documented with a 3D laser scan of the cutterhead conducted on September 18, 2020, by the Texas Department of Public Safety, Texas Rangers. The scans and measurements were provided to the NTSB Materials Laboratory.

Based on detailed photography, NTSB investigators selected three cutterhead teeth for metallurgical examination. Therefore, on October 27, 2020, the Orion Group and U.S. Coast Guard investigators removed and secured the following cutterhead teeth:[141]

- Tooth B3, half broken tooth, NTSB evidence control number DCA20FM026-OMS-005
- Tooth C1, scratch/gouge at the tip of the tooth, NTSB evidence control number DCA20FM026-OMS-006
- Tooth E3, visual evidence of metal transfer, NTSB evidence control number DCA20FM026-OMS-007

For further details of the cutterhead examinations see NTSB Materials Laboratory Factual Reports No. 21-022 and 21-023 contained in the docket for this investigation.

11.4. Other Physical Evidence

U.S. Coast Guard investigators collected the following pieces of debris found in the *Waymon Boyd* cutterhead pump strainer and on the deck of the dredge.

Evidence control number DCA20FM026-OMS-001:

- One (1) 50 pound, 17x13x3 piece of debris found in cutterhead suction pipe on September 19, 2020.
- One (1) 6 pound, 9x8x2 piece of debris found in the cutterhead pump strainer on September 24, 2020.
- One (1) 2 pound, 4x4x2 piece of debris found in the cutterhead pump strainer on September 24, 2020.
- One (1) 1 pound, 3x2x1 piece of debris found in the cutterhead pump strainer on September 24, 2020.

Evidence control number DCA20FM026-OMS-002:

- One (1) 20 pound, 13x12x4 piece of debris found on the port-side deck of the dredge *Waymon Boyd* on September 14, 2020.

On October 23, 2020, the Coast Guard shipped the above listed items to the NTSB Materials Laboratory for examination.

[141] The examination occurred at Central Boat Rentals in San Leon, Texas, where the Orion Group transported the salvaged dredge *Waymon Boyd* for secure storage.

11.5. Pipeline Inspection Detail

11.5.1. In-situ Inspection

On August 24, 2020, between 8:47 and 0911, an Enterprise commercial diving contractor performed a video-recorded post-accident survey of pipeline TX219, in which a diver and tender reported the following observations (refer to Figure 29):

- The pipeline was exposed such that there was about 1 foot of water under the damaged pipe segment.
- Two holes in pipeline were found near the 6:00 position.
- The larger hole (east) was about 7 in. longitudinal and about 5 in. transverse.
- The smaller hole (west) was about 5 in. longitudinal and about 2.5 in. transverse.
- The girth weld (No. 444000) was about 2 ft. 8 in. west of the smaller hole.
- Exterior concrete sleeving was missing from the pipeline around the breach. The concrete coating was intact 13 in. west of the girth weld.
- The distance between TX219 and the non-Enterprise 10-inch diameter pipeline was about 5 ft. 10 in. in the area where TX219 was damaged.
- The distance from the channel bottom to the bottom of the non-Enterprise 10-inch diameter pipe was about 1.5 feet.
- The distance from the 10-inch diameter pipe to the shoreline was about 11 feet (reference tide on August 24, 2020, at 0857).
- The distance from the shoreline to TX219 was about 16 ft. 10 in. at the location of the damage.
- The distance from the west shoreline riprap to the girth weld (No. 444000) was about 5 ft. 10 in.
- The distance from the girth weld to the east-side damaged concrete pipe coating was about 9 feet.
- The distance from the girth weld to where the pipeline touched channel bottom to the east was about 14 ft. The pipeline was completely under natural bottom cover at 22 ft. east of the girth weld.
- There was a gap in the concrete coating at the girth weld. The concrete coating to the west of the pipe breach was undamaged.
- The diver described the channel natural bottom as hard sand.

11.5.2. Post-recovery inspection

On December 3, 2020, NTSB investigators and investigative parties developed protocol for factually documenting the condition of the recovered pipeline segment and associated evidence items.

On December 10, 2020, upon uncrating the pipeline evidence at the NTSB laboratory facilities, investigators noted the pipeline segment damage consisted of five gouges, three dents, and two punctures with a fracture that intersected both punctures. Inward metal deformation, or lips of steel, were folded into the interior of the pipe (Figures 32 and 33). Pipe wall puncture damage was located between 31.3 inches and 45.5 inches east of girth weld 444000. All damage to the pipe, including punctures, gouges, dents, and fracture, occurred within a region between 25.5 inches and 57.8 inches east of girth weld 444000. As much as a 10-foot 5-inch length of the concrete coating was missing from the pipe in the general area of the damage (Figure 29). For further details of the pipeline segment and associated evidence examinations see NTSB Materials Laboratory Factual Report No. 21-022 contained in the docket for this investigation.

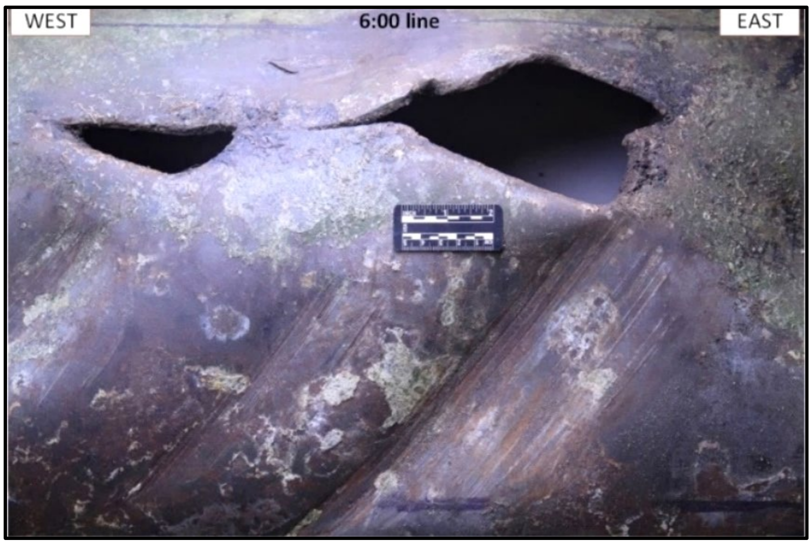

Figure 32. Pipeline breaching damage, exterior pipe wall surface. NTSB preliminary examination photograph after superficial surface cleaning, December 10, 2020.

Figure 33. Interior surface of pipeline coupon encompassing all visible damage. NTSB preliminary examination photograph, December 10, 2020.

12. Accident Witness Interview Summaries

The following are summaries of statements dredge crew accident witnesses provided to NTSB investigators concerning their observations and actions on the morning of the accident.

12.1. Dredge Captain

The following information about the accident was compiled from the transcript of the dredge captain's interview by NTSB investigators on January 6, 2021.

Prior to the accident dredging was progressing toward its closest approach to the shoreline during this project. Around 0730 to 0735, the leverman encountered debris with the cutterhead and called the dredge captain on the intercom to report the situation. The captain told the leverman to avoid the debris and get the coordinates and station number so the debris could be reported to the Orion Group office for later removal by other means.

About 0800, the captain was in his office completing a daily report when he heard the spuds being raised and lowered to walk the dredge forward about 3 feet for beginning a new set of dredge sweeps. Shortly afterward he felt the dredge shake like it hit something hard. The leverman called the captain over the intercom once again and said that he "hit a water line." The captain exited his office and observed a 25-foot-high waterspout shooting up as the dredge was moving away from the shoreline. He also noticed the dredge cutterhead/ladder had been raised.

Because he did not smell anything, the captain continued to believe that water was being released from a broken water line and he therefore did not use the kill-switch to shut down the dredge power. He returned to his office to find the telephone number for an EPIC representative to report what he thought was a broken water pipeline.

The explosion occurred as the dredge captain was in his office calling the EPIC representative. He stated that "all the fire was in my face…and it was burning on the side and in front of me." The door to his office was on the port side, where the explosion occurred, so he exited his office through a starboard side window. He went down a deck to warn those in the galley and berthing area but couldn't reach the space because of the fire. He subsequently jumped overboard from the starboard side second level. The leverman evacuated the leverman room and jumped overboard from the starboard side on the third level. He and the dredge captain swam aft along the vessel, then to shore.

12.2. Mate

The following information about the accident was compiled from the transcript of the mate's interview by NTSB investigators on August 31, 2020.

On the morning of the accident, the mate attended the safety meeting, which lasted about 20 to 30 minutes. Following the meeting, he went to the galley for breakfast. After receiving a work assignment to accompany the welder and take some equipment to another location, he boarded a small boat that had departed the dredge when the accident occurred. The mate was facing away from the dredge until his attention was drawn to the dredge by a noise. He observed water and gas spraying into the air. The small boat was about 200 feet away from the dredge when the explosion occurred.

The small boat sped up and proceeded further from the dredge until they saw another Orion crewmember running on the floating pipeline to get away from the fire. They turned the boat around and urged the crewmember to jump into the water, but he kept walking on the pipeline. They moved the boat toward the crewmember and picked him up.

They departed the area because of heat from the fire. They arrived at a landing and called for an ambulance to assist the injured crewman.

12.3. Tender operator

The following information about the accident was compiled from the transcript of the tender operator's interview by NTSB investigators on August 31, 2020.

About 0600 on the morning of the accident, the tender operator attended the morning safety meeting in the leverman's room and noted that dredge operations seemed to be normal. Following the 20-to-30-minute safety meeting, he went to breakfast in the galley. The dredge anchors had already been established before the tender operator began his shift. At that time, the dredge was operating about 75 feet from the shoreline and had progressed ahead (up-channel) of the cane poles.

He received an assignment to accompany the welder to Orion's supply barge, which was stationed close to a landing outbound from the dredging site. The tender operator prepared a 30-foot boat for launch, then returned to the leverman's room to complete paperwork for checking out the boat. The tender operator piloted the watercraft, with the welder and mate as passengers.

As the boat was outbound approaching the center of the shipping channel off the stern of the dredge, he heard the dredge rattling – "the whole vessel was shaking." As he turned around to look back, he saw a plume of water at the front of the dredge. Then he saw an indication of a gas-like waviness in the atmosphere surrounding the dredge. He described the gas as "when you open up a propane tank, when you see that gas coming out."

His passengers told him to "gun the boat," and he increased speed to get as far away as possible. He then heard the explosion. The tender operator said the time interval between his observation of the water plume and the explosion was only a couple of seconds. Their boat was about 300 feet from the dredge when the explosion occurred.

The welder and mate directed the tender operator to turn the boat around when they saw an injured Orion crewmember that had been on the dredge, running across the top of the floating dredge discharge pipeline to escape. They rescued the crewmember, took him to the landing, and called for an ambulance.

12.4. Oiler-in-training

The following information about the accident was compiled from the transcript of the oiler-in-training's interview by NTSB investigators on August 23, 2020.

On the morning of the accident about 6:00 AM, the oiler-in-training was stationed on the Booster #1 vessel along with the senior oiler who was training him. Booster #1 was connected to the discharge hose of the *Waymon Boyd* suction dredge and was in turn connected to the Booster #2 vessel, making it possible to pump dredge material away from the work area over a longer distance.

While the oiler-in-training was working in the Booster #1-gauge room, he observed a loss of prime, or suction pressure, which he believed caused the pump motor speed to drop from about 900 rpm to about 430 rpm over a period of a couple of minutes. He attempted to notify the dredge captain of the loss of prime by radio but was unable to get any answer. The two oilers decided to "release the clutch" which disengaged the pump impeller. Within minutes the senior oiler advised the oiler-in training to come outside onto the deck, where they could observe a fireball and smoke surrounding the barge. After opening a 2-inch bleeder valve on the booster pump, the two waited about 10 minutes trying to get someone's attention and finally decided to abandon the vessel and wade ashore in the 4-foot-deep water.

12.5. Deckhand #1

The following information about the accident was compiled from the transcript of the deckhand #1's interview by NTSB investigators on August 31, 2020.

Deckhand #1 arrived to work on the dredge about 0600 on the morning of the accident. He signed in and reported to the leverman's room to attend the morning safety meeting for about 30 minutes. He then went to the galley for breakfast.

Following that, crewmembers discussed the work they planned to do that day. Deckhand #1 was asked to assist the welder. Deckhand #1 and the welder then boarded the starboard side anchor barge and from there entered a small boat with the tender operator who piloted the boat. They untied the boat and began making way toward the other anchor barge where the welder planned to work. At that time, Deckhand #1 estimated the dredge was operating about 100 feet or less from the shoreline.

As they were underway traveling away from the dredge, deckhand #1 turned around to see the dredge "moving to the left" and he then saw gray liquid blowing high into the air in front of the dredge and he also heard a splashing noise. Then he observed what he believed to be a gas, as evidenced by a rippling effect or waviness in the air. The explosion occurred about 5 to 10 seconds after he noticed the waviness in the air. Within a couple of seconds, flames covered almost the entire dredge.

Deckhand #1 saw a coworker, who was badly burned and trying to escape the dredge by running on the floating dredge discharge pipeline. Deckhand #1 and the welder managed to get the coworker into their boat. They then went ashore.

Deckhand #1 described the flames as "very, very strong," and the intensity remained the same for a "long time."

12.6. Deckhand #2

The following information about the accident was compiled from the transcript of the deckhand #2's interview by NTSB investigators on August 31, 2020.

Deckhand #2 arrived to work at the dredge about 0600 on the day of the accident. He attended the morning safety meeting as soon as he arrived. After the meeting, he went down to the worksite to see what needed to be done. It was before 0800 when he was told to accompany the mechanic to landing to retrieve some equipment. Deckhand #2 piloted the small boat and was accompanied by the mechanic. As they were about to arrive at the landing, about 4,000 to 5,000 feet from the dredge, they heard a loud explosion and turned around to see the dredge on fire.

12.7. Booster #1 Engineer

The following information about the accident was compiled from the transcript of the Booster #1 engineer's interview by NTSB investigators on September 1, 2020.

At 0600 on the day of the accident, the Booster #1 engineer attended the morning safety meeting in the dredge leverman's room. He then reported to Booster #1 to begin his shift. Until the time of the accident, the booster equipment was operating normally. Booster #1 was situated about 100 meters (330 feet) from the dredge.

The Booster #1 engineer was below deck when he noticed the dredge discharge pipeline booster pump pressure dropped from its normal pressure of 150 psig to zero and the booster barge began shaking. He heard an associated noise suggestive of solid material scraping in the pipe. The Booster #1 engineer made a radio call to the dredge to report the loss of pressure and shaking, but he did not receive any response.

Compared to other occasions when there was loss of booster pump pressure and shaking, the shaking was much stronger, and the noise was different. He was unaware of the explosion until notified by the oiler. Within seconds of the booster pump pressure loss, he went on deck and observed the fire and smoke.

He then shut down the booster pump. After about 5 minutes, considering large ships in the area carrying hazardous material, he and his crewmate jumped into the water and waded ashore about 10 meters (33 feet).

12.8. Booster #2 Engineer

The following information about the accident was compiled from the transcript of the Booster #2 engineer's interview by NTSB investigators on September 1, 2020.

At 0530 on the day of the accident, the Booster #2 engineer arrived at the landing and entered a boat that took him to the dredge. After signing in, he attended the morning safety meeting. Following the meeting, he reported to Booster #2, which was located about 8,000 feet from the dredge. Prior to the accident the Booster equipment was functioning properly.

While in the tool room, he heard over the radio the crew of Booster #1 calling the leverman to report that its pumps were shaking. Shortly after that, the engineer radioed the leverman to report that Booster #2 pumps were also shaking, and the dredge discharge pipeline pressure decreased. The leverman did not respond.

The Booster #2 engineer then heard an explosion. After checking controls, he went on deck and saw the smoke, but was unable to see the dredge from his location. He shut down the booster barge pumps and was then taken aboard a small boat to the landing.

12.9. Welder

The following information about the accident was compiled from the transcript of the welder's interview by NTSB investigators on September 1, 2020.

On the day of the accident, the welder arrived to work at 0530. He first attended a safety meeting. Operations seemed normal that day. The dredge captain assigned him to go to a site where some pipes required welding, as soon as sunrise occurred. He gathered equipment and entered a boat with the tender operator and mate.

While sitting in the boat and still tied up to the dredge, he observed a waterspout shooting 50 to 60 feet in the air. Then gas seemed to be coming out of the water. He only heard noise from the engines and motors that were running at the time. He did not notice any unusual vibrations on the dredge. Because they saw gas vapor in the air, they untied the boat and had motored about 250 to 300 feet away from the dredge before the explosion happened. They could feel the heat from the fire.

He saw a person with burn injuries appear on the outside of the dredge, who was calling for the boat to return. They turned the boat around but couldn't approach the injured person because of the heat. The burned individual started running on top of the floating pipeline to get away from the dredge so the boat would be able to approach. Once he traversed about 8 pipe-sections from the dredge, the boat was able to rescue the injured individual and transport him to the landing.

13. Post Accident Actions

In response to NTSB investigator's request for the Orion Group to identify post-accident policy or best-practice changes for the inclusion of utilities and infrastructure on its DREDGEPACK® software module, the Orion Group responded that it had no such written procedures and, "nothing has change[d] according to how we operate pre/post incident."

However, the Orion Surveyor told NTSB investigators, "currently, all the information that we can get anywhere in the area, we're putting that on [DREDGEPACK®] now."[142] Although it is not a written policy, the surveyor said it was a decision company managers made that if

[142] Orion Group surveyor, p. 28-29.

infrastructure such as pipelines are anywhere in the area, the company should include the location of such facilities in the DREDGEPACK® “just to be on the safe side.”

14. Federal and State Regulations

14.1. Summary of Federal Pipeline Safety Regulations

The Hazardous Liquid Pipeline Act of 1979 is the principal act establishing the federal role in hazardous liquid pipeline safety.[143] The Act expanded existing statutory authority for hazardous liquids pipeline safety regulation, which had been limited to transportation in interstate and foreign commerce. In 1981, the Research and Special Programs Administration issued a final rule amending 49 CFR Part 195 to conform to the provisions of the Act.[144] With the absence of applicable federal regulations at the time pipeline TX219 was constructed in 1968, voluntary industry standards available for liquid pipeline design, construction, operation, and maintenance were found in ASME B31.4, *Oil Transportation Piping Systems*, originally published in 1959, with a subsequent edition issued in 1966.[145]

14.1.1. Cover Over Buried Pipeline (49 CFR 195.248)

Current requirements for cover over buried pipeline state that for the Gulf of Mexico and its inlets in waters less than 15 feet deep as measured from mean low water, pipe must be installed so that it is provided with cover between the top of the pipe and the ground level, roadbed, river bottom, or underwater natural bottom. In industrial, commercial, and residential areas, 36 inches of cover must be provided for normal excavations where blasting is not required. The cover requirements apply to pipelines at the time of construction or when a pipeline is subsequently replaced, relocated, or otherwise changed. The cover requirements are not mandatory for pipelines in operation before April 1, 1970.[146] Additionally, there are no specific regulatory requirements for reburial of exposed onshore pipelines, or for pipelines with less that the required cover at the time of construction.

On January 12, 2021, Enterprise responded to NTSB investigators that it considered the text of the regulation and confirmed that it does not apply to Line TX219 given its construction

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[143] 49 U.S.C. 2001 *et seq*.

[144] 46 *Federal Register* 38357, July 27, 1981.

[145] ASME B31.4 is now titled “*Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*.” Current federal pipeline safety regulations at 49 CFR 195.3 incorporate by reference the 2006 edition of the standard.

[146] Interpretation Response #PI-75-040, published August 1, 1975, (Office of Pipeline Safety Operations). See: https://cms7.phmsa.dot.gov/regulations/title49/interp/PI-75-040

date and the fact that the pipeline had not been relocated, replaced, or otherwise changed since it was installed in 1968.[147]

14.1.2. Operation and Maintenance General Requirements (49 CFR 195.401)

Section 195.401(b)(1) states that whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition. Section 195.401(b)(2) further requires that when an operator discovers a condition on a pipeline covered under the integrity management requirements for pipelines in high consequence areas of §195.452, the operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity management assessment or information analysis.

14.1.3. Inspection of rights-of-way and crossings under navigable waters (49 CFR 195.412).

The regulation requires that operators shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Except for offshore pipelines, operators shall inspect crossings under a navigable waterway to determine the condition of the crossing at intervals not exceeding 5 years.

14.1.4. Underwater Inspection and Reburial of Pipelines in the Gulf of Mexico and its Inlets (49 CFR 195.413)

This section prescribes requirements for operators of pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. Rivers, tidal marshes, and canals are excluded. The regulation requires operators to assess the risk of such pipelines being exposed or being a hazard to navigation. Among the requirements, the operator must promptly notify the National Response Center within 24 hours, and within 7 days of discovery and mark the location of the pipeline in accordance with 33 CFR Part 64. Within 6 months of discovery, the pipeline must be provided 36 inches of cover below the underwater natural bottom (18 inches in rock).

In its correspondence with NTSB investigators, Enterprise stated that the regulation does not apply to Line TX219 because it is not located in the Gulf of Mexico or its inlets as defined in 49 CFR 195.2, which states:

[147] J. Morton, Enterprise Products, letter (regarding information request dated December 8, 2020; response to request 105) addressed to L. Wisniewski, National Transportation Safety Board, January 12, 2021.

Gulf of Mexico and its inlets means the waters from the mean high-water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.[148]

Enterprise stated this regulatory definition excludes rivers, tidal marshes, lakes, and canals, such as the Tule Lake Channel where Line TX219 is located. Enterprise further stated that the channel is a controlled-access canal and is not a part of the Gulf of Mexico.[149]

14.1.5. Damage Prevention Program (49 CFR 195.442)

Federal damage prevention program requirements mandate that operators of a buried pipeline must establish a written program to prevent damage to the pipeline from mechanical excavation activities. An operator may comply with any of the damage prevention program requirements by participation in a One-Call system.

The damage prevention program must identify persons who normally engage in excavation activities in the area in which the pipeline is located. The program must also provide for notification of the public in the vicinity of the pipeline and identified excavators as often as needed to make them aware of the damage prevention program and how to obtain information about the location of underground pipelines before excavation activities begin.

The program must also provide a means of for the operator to receive notification of planned excavation activities. If the operator has buried pipelines in the area of excavation activity, the program must provide for notification to persons who give notice of their intent to excavate, including a description of the type of temporary marking to be provided and how to identify such markings. Temporary markings for buried pipelines should be placed in advance of the excavation activity.

[148] J. Morton, January 12, 2021.

[149] In the Preamble to the Final Rule, the Research and Special Programs Administration (RSPA) clarified that the Rule implements Public Law 101-599, which "was enacted to address the consequences of recent accidents involving fishing vessels that struck pipelines in shallow waters in the Gulf." See Inspection and Burial of Offshore Gas and Hazardous Liquid Pipelines, 56 *FR* 63,764 (December 5, 1991). The Preamble indicates that Public Law 101-599 was specifically passed "to assure that pipelines in shallow offshore waters where commercial fishing vessels navigate will not pose a hazard to those vessels." Moreover, in an effort to better define the term "inlet" for the benefit of pipeline operators, RSPA included a list submitted by the Fisheries Institute, which identified inlets "where menhaden and other commercial activities take place." The Tule Lake Channel is not accessed by commercial fishing vessels.

If the operator has reason to believe an onshore pipeline could be damaged by excavation activities, it must provide for inspection during and after excavation activities to verify the integrity of the pipeline.

14.1.6. Pipeline Integrity Management in High Consequence Areas (49 CFR 195.452)

Hazardous liquid pipelines located in high consequence areas must have had in place, by 2001 – 2003 depending on certain operator circumstances, programs and practices to manage pipeline integrity. The regulation requires a written integrity management program that addresses risks on each pipeline segment, including measures necessary to prevent and mitigate the consequences of a pipeline failure.

Among the integrity management program requirements are the following:

- A process for identifying which pipeline segments could affect a high consequence area,
- A baseline assessment plan in accordance with §195.452(c), using inline integrity inspection tools,
- An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure,
- Criteria for taking remedial actions in accordance with §195.452(h) to address anomalous conditions identified by integrity assessments and information analyses,
- A continual process of assessment and evaluation to maintain the pipeline's integrity, and
- Identification of preventative and mitigative measures to protect the high consequence area.

In periodically evaluating the integrity of each pipeline segment for an information analysis specified in §195.452(g), an operator must analyze all available information about the integrity of its entire pipeline and the consequences of a possible failure along the pipeline. Attributes about the pipeline that must be integrated in the operator's information analysis are various pipeline construction details, integrity assessment data, and depth of cover surveys, to name a few.

Appendix C to Part 195 provides further guidance on risk factors that the operator should evaluate, such as the nature and characteristics of the product transported in the pipeline.

14.1.7. Integrity Assessments for Certain Underwater Hazardous Liquid Pipeline Facilities Located in High Consequence Areas (49 CFR 195.454)

Notwithstanding any pipeline integrity management program or integrity schedule otherwise required under §195.452, the regulation applies to operators of any underwater hazardous liquid pipeline facility located in a high consequence area that is not an offshore pipeline facility, and any portion of which is located at depths greater than 150 feet. Among the requirements are pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology, on a schedule based on the risk the pipeline poses to the high consequence area.

Enterprise told NTSB investigators the regulation does not apply to Line TX219 because no portion of Line TX219 is located at depths greater than 150 feet under the surface of the water, and thus, the integrity assessments required in this regulation are not applicable.[150]

14.2. Summary of State of Texas Regulations

The Hazardous Liquids Pipeline Safety Act of 1979 provided for exclusive federal regulation and enforcement for those pipelines transporting hazardous liquids in interstate and foreign commerce. For intrastate pipeline facilities, the Act provides for the same federal regulation and enforcement unless a state assumes those responsibilities.[151] The Railroad Commission of Texas has primary regulatory jurisdiction over pipeline transporters in the state.

State regulations pertaining to underground pipeline damage prevention are found in Title 16, Part 1, Chapter 18 of the Texas Administrative Code. Sections of the Code apply to both pipeline operators and excavators engaged in the movement of earth in the vicinity of an underground pipeline containing flammable, toxic, or corrosive gas, a hazardous liquid, or carbon dioxide.[152] The Code defines excavation as the movement of earth by any means, and thus the Railroad Commission of Texas interprets dredging in the vicinity of an exposed pipeline as an excavation activity.

In general, the Code requires the excavator to notify a notification center prior to commencing work and obligates the excavator to avoid damaging underground pipelines. Applicable provisions of the Code include the following:

14.2.1. Rule 18.3 Excavator Notice to Notification Center

An excavator must contact the notification center in accordance with Chapter 251 of the Texas Utilities Code. For large projects that cannot be fully described by online locate tickets, the operator and excavator must conduct a face-to-face meeting to discuss the excavation activities and establish protocols for:

1. the interval between each notice to the notification center,

[150] J. Morton, January 12, 2021.
[151] Appendix A to 49 CFR Part 195.
[152] See https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=18&rl=Y

2. the scope of each line-locate ticket,
3. the life of each line locate ticket, and
4. the schedule of work on the excavation and the chronological order in which applicable locate tickets are to be marked.

14.2.2. Rule 18.6 General Marking Requirements

All pipeline markings must conform to the requirements of American Public Works Association (APWA) Uniform Color Code (ANSI Standard Z535.1, Safety Color Code). The APWA encourages public agencies, utilities, and contractors to adopt the Uniform Color Code and Safety Colors for temporary marking and facility identification (Figure 34).

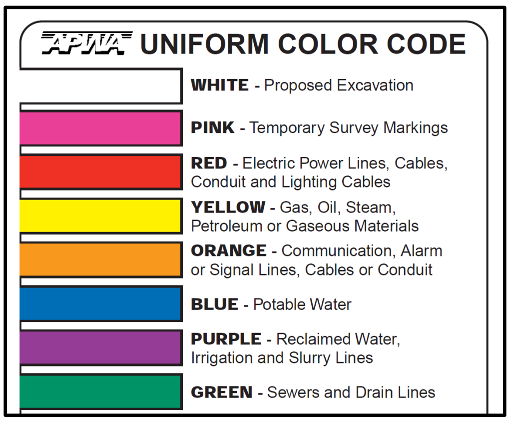

Figure 34. American Public Works Association Uniform Color Code for temporary marking.

The standard states that to increase the visibility of temporary markings, color coded vertical markers, such as stakes or flags, should supplement surface markings.

14.2.3. Rule 18.7 Excavator Marking Requirements

Rule 18.7(a) requires that prior to giving notice pursuant to Rule 18.3, an excavator shall mark, if applicable according to §18.3(c), the specific excavation area using white paint flags, or stakes, whichever is most visible for the terrain. Furthermore, under Rule 18.7(b), the excavator shall mark the area of excavation using intervals that show the direction of the excavation.

14.2.4. Rule 18.8 Operator Marking Requirements

Rule 18.8(b) requires that locators mark the approximate center line of an underground pipeline. Furthermore, Rule 18.8(d) of the Code states that where a proposed excavation crosses an underground pipeline, markings shall be placed at intervals that "clearly define the route of the underground pipeline, to the extent possible." The rule states that markings shall consist of "stakes, paint, flags, or a combination of two or more of these." Section (f) of the Rule specifies that markings be placed at sufficient intervals to indicate the approximate horizontal location and direction of the underground pipeline and the distance between any two marks shall not exceed 20 feet. Furthermore, section (g) states that markings of an underground pipeline greater than six inches in nominal outside dimension shall include the size in inches at every other mark. The locator must extend all markings, if practical, at least one additional mark beyond the boundaries of the proposed work zone.

14.2.5. Rule 18.9 Options for Managing an Excavation Site in the Vicinity of an Underground Pipeline

This regulation provides recommended voluntary protocols for operators and excavators to jointly establish for excavations in the vicinity of underground pipelines, depending on the scope of the excavation and the particular characteristics of each job. According to Section (a)(9), the protocol may designate the extent of a tolerance zone, provided that it shall not be less than half the nominal diameter of the underground pipeline plus a minimum of 18 inches on either side of the outside edge on a horizontal plane. The protocol may also include the type of excavation permitted within the tolerance zone and provide for any other agreement with respect to excavation activities and/or marking requirements to ensure safe excavation in the vicinity of an underground pipeline. If an excavator and an operator jointly establish protocols pursuant to this section, a record of such an agreement is required to be maintained by the excavator and the operator. The Railroad Commission of Texas enforces the terms of damage prevention protocols when there is a written agreement between the parties.

14.2.6. Rule 18.10 Excavation within Tolerance Zone

The excavator must comply with the requirements of Texas Health & Safety Code, Subchapter H, relating to Construction Affecting Pipeline Easements and Rights-of-Way. When excavation is to take place within the specified tolerance zone, an excavator shall exercise such reasonable care as may be necessary to prevent damage to any underground pipeline in or near the excavation area.

15. Applicable Recommended Practices and Guidance

15.1. PHMSA Marine Damage Prevention Awareness

PHMSA provides pipeline safety information on its website relative to marine damage prevention, including references to the Council for Dredging and Marine Construction Safety guidance discussed in Section 15.2 of this report.[153] The PHMSA website also provides

[153] See: https://www.phmsa.dot.gov/safety-awareness/pipeline/marine-damage-prevention (Accessed February 26, 2021).

references the Coastal and Marine Operators Pipeline Industry Initiative discussed in Section 15.3 of this report.

In 1999, the Department of Transportation (DOT) sponsored a study of One-Call systems and damage prevention best practices (Common Ground Study).[154] The study's purpose was to identify and validate existing best practices to prevent damages to underground facilities. The best practices were intended to be shared among stakeholders involved with operation, maintenance, construction, and protection of underground facilities.

Among several consensus best practices identified in the Common Ground Study for locating and marking pipelines were such practices as using a uniform color code and set of marking symbols; ensuring that facilities are adequately marked for the conditions and extend a reasonable distance beyond the bounds of the requested area; and communications with pre-location meeting to ensure precise understanding of the scope of the excavation site. Suggested practices for future consideration included efforts to improve the accuracy of information provided on a locate request, including the use of a common data base, GPS, and other evolving technologies.

The Common Ground Study identified several best practices specific to excavation, which included:

- White lining. When the excavation site cannot be clearly and adequately identified on the locate ticket, the excavator designates the area to be excavated using pre-marking prior to the arrival of the locator. The excavation area is marked with white paint, flags, stakes, or a combination of these to outline the dig site prior to notifying the One-Call system and before the line locator arrives on the job. PHMSA has compiled a summary of state damage prevention laws, which indicate that 37 states and Puerto Rico, including the State of Texas, have enacted various provisions for white lining.[155]
- Pre-excavation meetings. When practical, the excavator requests a meeting with the pipeline locator at the job site prior to actual marking of facility locations. The meeting is intended to facilitate communications, coordinate the marking with actual excavation, and assure identification of high priority facilities.
- Locate verification. Prior to excavation, the excavator verifies the dig site matches the one-call request and confirms that all facilities have been marked.

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[154] *Common Ground Study of One-Call Systems and Damage Prevention Best Practices* (Washington DC: Department of Transportation, 1999). In 1998, Congress passed the Transportation Equity Act for the 21st Century, in which the DOT was instructed to conduct a study of best practices in place nationwide for enhancing worker safety, protecting vital underground infrastructure, and ensuring public safety during excavation activities in the vicinity of underground facilities. The DOT charged the former Office of Pipeline Safety (now PHMSA) with conducting the study.

[155] https://primis.phmsa.dot.gov/comm/damageprevention.htm, (accessed March 4, 2021). See Title 16, Part 1, Chapter 18.7 of the Texas Administrative Code.

- Work site review with excavator crews to share information about the location of underground facilities.
- Facility avoidance. The excavator uses reasonable care to avoid damaging underground facilities and plans the excavation to minimize interference with underground facilities in or near the work area.
- Excavation observer. The excavator has an observer to assist the equipment operator when operating excavation equipment around known underground facilities.

15.2. Council for Dredging and Marine Construction Safety

Orion Marine Group is a member of the CDMCS. The organization's mission is to create an injury-free workplace and safety-first culture for the dredging and marine construction industry. Furthermore, the CDMCS states that its mission is to share best practices, apply lessons learned, and actively partner with the U.S. Army Corps of Engineers, and other federal, state and local government agencies and stakeholders.[156]

In response to marine pipeline accidents, such as the gas pipeline struck by a dredge in Matagorda Bay near Port O'Connor, Texas, in April 2018, the CDMCS Pipeline Task Force was formed. The Pipeline Task Force is a joint inter-agency, public-private initiative focused on ensuring safe dredging operations in ports and waterways with submerged gas and hazardous liquid pipelines through enhanced communication, collaboration, and exchange of best practices among all stakeholders.

In January 2020, the CDMCS published a pipeline incident prevention best practices guide to promote safe dredging and construction operations near underwater gas and hazardous liquid pipelines.[157] Also in 2020, the CDMCS also published a "Checklist for Safe Dredging Near Underwater Gas & Hazardous Liquid Pipelines." These documents provide guidance for dredging companies for planning, identifying, and avoiding pipelines. This guidance is directed to all involved dredge project personnel, including project engineers, project managers, superintendents, captains, and equipment operators.

The CDMCS best practices guidance states that communication is the most important action to keep the personnel aboard vessels safe. This includes surveying and marking pipelines before commencing operations and communicating timeframes and the type of work to be performed. The guidance includes suggestions for dredging companies to invite pipeline companies to planning meetings and for holding a preconstruction meeting to provide the

[156] See: https://cdmcs.org/vision-mission/ (Accessed February 26, 2021).

[157] *Pipeline Incident Prevention Recommended Best Practices Guide for Safe Dredging near Underwater Gas & Hazardous Liquids Pipelines.* (Washington DC, Council for Dredging and Marine Construction Safety. 2020). The recommended practices are applicable to operations conducted in United States Army Corps of Engineers (USACE) federal navigation channels, including those channels USACE contracts with industry to dredge for others.

pipeline company a project overview, agreement for timelines, and evaluation whether a pipeline company representative should be onsite during the work near pipelines to assist in proper avoidance measures. The guidance advises the dredging company to contact a One-Call center at least 7 business days before starting work. The dredging company notification should include all locations where any water bottom or wetland contact may occur, including dredged material placement areas.

Furthermore, the CDMCS guidance addresses respect for tolerance zones that may be established by the pipeline operator, project plans and specifications, and/or state laws.[158] The guidance cautions that pipeline companies and dredging companies generally have in-house tolerance zones or "no-go-zones" where work may be unsafe or have special conditions. According to the guidance, state tolerance zone requirements generally are designed for on-land application and may not apply to marine activities such as dredging. Thus, tolerance zones vary among dredging companies, with 75 feet being the no-go working distance for most.

The CDMCS guidance suggests that dredging companies should incorporate in its safety plan elements of the pipeline company's safety, environment, and emergency response plans. The guidance suggests that the dredging company verify that all project and vessel personnel are familiar with the plan.

The CDMCS recommends that project emergency plans include provisions for how to identify a pipeline leak and how to respond to emergencies. The guidance states that crews should be trained to recognize signs of pipeline leaks such as continuous bubbling, blowing, or hissing sound from the water. The guidance document provides an emergency checklist for actions that should be taken immediately following a suspected pipeline strike, including:

- Immediately stopping all operations in the event of a leak,
- Shutting down possible ignition sources: motors, generators, lights, etc.,
- Account for crewmembers and communicate the hazards to them,
- Call 911, Channel 16, or the Coast Guard,
- If possible, drift out of the area before starting an ignition source and evacuate the vessel if needed.

The CDMCS also recommends that project plans should have certain basic pipeline information stored in multiple readily available locations:

- List of all pipelines in the project scope,
- List of products in each pipeline,
- Diameter of the pipeline,

[158] Tolerance zones are areas near pipelines defined as the horizontal distance extending from the outer edge or wall of a pipeline where no activity or work should occur.

- Emergency contact numbers for the pipeline company.

For pipeline companies, the CDMCS guidance advises that dredging and marine construction are more complicated than on-land excavation activities, and that pipeline companies should attend planning, pre-construction, and kick-off meetings hosted by the dredging company. The guidance includes a list of questions that pipeline companies should ask dredging companies. The guidance also suggests that pipeline companies:

- Consider asking to be onsite when dredge or other equipment is nearing the pipeline,
- Ensure the dredging company is familiar with how the pipeline is marked,
- Tell the dredging company if pipelines cannot be accurately marked or surveyed due to water conditions and provide GPS coordinates as an option.

15.3. Coastal and Marine Operators Pipeline Industry Initiative

Among other things, the Coastal and Marine Operator's Pipeline Industry Initiative (CAMO) was organized to address challenges in preventing damage to coastal and marine pipelines. CAMO has published public safety announcements and other guidance documents that are available from its website.[159]

In 2019, CAMO published a guide of recommended best practices for working near underwater pipelines.[160] Intended to promote safe dredging and marine construction operations near underwater pipelines, the guide provides:

- General information about pipeline types, their markings, and signage,
- Overview of the One-Call process,
- Procedures for avoiding pipelines by the establishment of tolerance zones,
- Procedures for obtaining and providing pre-project information about the project scope and surveying for existing pipelines, and
- Safety, environment, and emergency response planning,
- Overview of dredging operations for pipeline operators, and
- Suggested timeline and objectives for planning projects near underwater pipelines.

The guidance for marine construction personnel for planning and avoidance of underwater pipelines state that it is important to know the product in each pipeline because they may vary in volatility and have different characteristics when released. The guide suggests that the product should be clearly stated in contingency plans to minimize safety risks if a release occurs. The guide further suggests that all project plans should have basic pipeline information stored in multiple readily available locations.

[159] http://www.camogroup.org/downloads/ (Accessed February 26, 2021).
[160] *Working Safely Near Underwater Pipelines, Recommended Best Practices Guide,* (Camo Group, 2019). The CAMO Group is an industry consortium composed of pipeline operators and industry stakeholders.

The guide cautions that understanding the operating pressure of a pipeline in the project area could help establish the level of risk and precautions. The guide states that even if a pipeline rupture occurs and the pipeline is shut down, it can take several hours for the pressure to bleed down to a safe level.

The guide states that depth of cover of an underwater pipeline can vary widely and natural forces may cause an underwater pipeline to become shallower over time. The guide cautions that pipelines will usually be shallower near the shoreline or riverbank.

The guide cautions construction personnel not to rely on maps and other third-party sources of pipeline location information. Instead, the guide suggests that location data and work-limit boundaries should always be provided by the pipeline company. The guidance states "it is essential that both the project manager and the pipeline company representative have direct and detailed discussions on the locations of all underwater pipelines that could be impacted."[161]

The CAMO best practices guide suggests that marking pipelines in marine areas is very challenging because markers can be accidently moved or removed by weather events, wave action, vessels, and erosion. The guide states that temporary pipeline markers may include such things as buoys, cane poles or PVC pipe. The guide states that the pipeline company may provide GPS coordinates to electronically mark the pipeline aboard the dredge and marine vessels.

The guide states that tolerance zones as defined in state laws are designed for on-land application and are too small for marine activities. The guide states that although tolerance zones vary among dredging companies, 75 feet appears to be the no-go working distance for most.

The CAMO best practices guide states the main signs of a pipeline leak include continuous bubbling, blowing, or hissing sound from the water. The guide recommends having active gas detectors during operations because gases may be odorless. The guide also provides a list of recommended actions to take after a pipeline leak, such as shutting down ignition sources, drifting out of the area, and evacuation.

15.4. Common Ground Alliance Damage Prevention Best Practices

In 2000, the Common Ground Alliance (CGA) was formed to further the work of the aforementioned 1999 PHMSA Common Ground Study.[162] The CGA best practices are

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[161] CAMO Group, 2019. See section 1.8 of the *Recommended Best Practices Guide*.

[162] The CGA is comprised of about 1,600 volunteer members who work together to identify and promote best practices for the protection of underground utilities. The CGA consists of working committees that include best

intended to improve worker safety, protect vital underground infrastructure, and ensure public safety during excavation activities conducted near existing underground facilities.

In 2020, the CGA published the latest edition of its best practices manual, which was based on the findings of the Common Ground Study.[163] Applicable sections of the best practices manual include, but are not limited to, the following guidance:

- Designers indicate existing underground facilities on drawings during planning and design.
  During the planning and design phases of the project, existing underground facility information gathered from field-located facilities and surveys are shown on plans. The plans are distributed to facility owners and operators to clarify information and identify conflicts.
- The project owner or project designer requires contractors and facility owners/operators to attend a mandatory pre-bid conference, during which requirements to protect utilities in the project area are discussed.
- Continuous interface between the designer and the contractor throughout the construction phase, including the designer's availability for preconstruction conferences, unforeseen conditions, and design changes.
- Providing excavators with information communicated to facility owners, operators, and locators by the One-Call center in response to the locate request allows the excavator to verify the accuracy of the information.
- Facility marking that matches expected surface and environmental conditions, which may include combinations of paint, chalk, flags, stakes, etc. All markings extend a reasonable distance beyond the bounds of the requested area.
- For locating and marking in navigable waterways, permanent markers are placed as close as practicable to entrance and exit points. The guidance states that proper placement and maintenance of visible permanent markers raise awareness of underwater facilities. Markers include the words "do not anchor or dredge" and/or applicable warning language.
- Temporary markers in navigable waterways, such as buoys, poles, or PVC markers, are used to indicate the presence of an underwater facility in an area. These markers may be supplemented with mapping, GPS coordinates, and/or fixed high-bank marks. The guidance states "it is critical for stakeholders to maintain communication throughout the excavation to ensure the safe and successful completion of the project."
- When the excavation site cannot be clearly and adequately identified on the locate ticket, the excavator designates the area to be excavated using white pre-marking,

practices, technology, educational programs, data reporting and evaluation, regional partners, stakeholder advocacy, and One-Call systems.

[163] *The Best Practices Manual – Version 17.0* (Alexandria, Virginia, Common Ground Alliance, 2020).

either onsite or electronically without the need for a site visit. The guidance states the technology allows the excavator to identify for the locate technician a clear delineation of their proposed excavation area.

15.5. API Recommended Practice 1160

American Petroleum Institute (API) Recommended Practice 1160, Managing System Integrity for Hazardous Liquid Pipelines, provides guidance to the pipeline industry for developing a pipeline integrity program.[164] The guidance recommends identifying threats to the integrity of pipelines and pipeline facilities, assessing the risk of a release from one pipeline segment to another, and mitigating the risk by removing identified threats. Examples of recommended preventative and mitigative measures to address weather or outside force damage include installation of protective mats or preplacement of river crossing with directional drilled pipeline.

For the prevention of third-party damage, the recommended practice suggests the operator's damage prevention program include, among other things, provisions for providing timely temporary marking of any portion of the operator's system that falls within the location scope of a One-Call ticket; establishing written guidelines for excavators authorized to work on the right-of-way stating what procedures an excavator should follow; and providing a full-time observer while excavation is in progress on, or in proximity to the pipeline.

For the locating and marking of pipelines that could be affected by excavation or encroachment activity, the recommended practice states that if the operator is certain that the excavation will not encroach upon any pipeline facilities the operator should notify the One-Call center or the excavator that no pipeline facilities will be impacted. However, if the excavation will be "on or close" to the operator's right-of-way, the operator should promptly locate and mark the pipeline and renew any markings if they become displaced or degraded.

15.6. API Damage Prevention Toolbox

The API published a website containing collection of damage prevention shared learnings and practices for onshore hazardous liquid transmission pipeline operation, known as the Damage Prevention Toolbox.[165] Although the Toolbox is not intended as a recommended practice, the learnings and practices outlined are provided to pipeline operators for consideration when analyzing, reviewing, or modifying existing procedures. Among the topics addressed are excavation job planning, excavation monitoring and observation, line locating and temporary marking, One-Call notification screening, pipeline depth of cover, and right-of-way patrol.

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[164] API Recommended Practice 1160, 3rd Edition, (Washington, DC, American Petroleum Institute, 2019).
[165] http://dptoolbox.org, accessed April 2, 2021.

The Toolbox lists numerous considerations for planning an excavation near pipelines, including surveying the area to identify and locate underground structures and white lining the proposed construction and excavation area prior to One-Call notifications.

Factors affecting the need for excavation monitoring and observation include the proximity of excavation work to the pipeline and the type of equipment and the potential impact on the pipeline. Suggestions contained in an example of an excavation safety checklist include walking through the work area with the excavator to communicate pipeline locations, monitoring the excavation site daily when work is performed within 25 feet of a company pipeline, and having the excavator notify the pipeline company prior to excavating within a certain distance of the pipeline.

The Toolbox describes three methods operators generally use to screen One-Call tickets, including clearing by map, clearing by contact, and clearing by site visit. Clearing by map can be accomplished when an operator is able to verify their mapping system does not conflict with dig site location provided in the One-Call ticket. Clearing by contact is done when it is necessary to obtain more information from the excavator about the work scope and location than what is described on the One-Call ticket. Clearing by site visit is done if the operator believes the proposed excavation has the potential to affect the pipeline.

Operators may consider clearing by site visit when additional information is needed to validate the scope and location of the excavation work. Among the considerations the Toolbox suggests for clearing a One-Call ticket during a site visit are the following:

- Does the excavator have a proven record of following pipeline company procedures and requirements?
- Has the proposed excavation area been white lined or marked by the excavator (is the area a well-defined excavation area)?
- Does the work plan indicate the need for special considerations or individual operator designated procedures, such as dredging?

The Toolbox section that addresses depth of pipeline cover states that although pipelines are installed to meet or exceed minimum regulatory requirements at the time of construction, they may become shallow or exposed due to excavation activities or various environmental factors. Operators may identify shallow or exposed pipelines by methods such as right-of-way patrols, depth of cover surveys, and line locating and maintenance activities. To evaluate whether the depth of cover of existing pipelines warrants further analysis, operators may consider evidence of significant cover loss, ongoing and past erosion, HCA locations, previous third-party damage, and location within a waterway. Mitigation methods include adding cover over pipelines, the use of protective barriers and casing, lowering or relocating the pipeline, providing additional signage, and increasing public awareness.

16. Previous NTSB Investigations

16.1. Matagorda Bay, Texas, 2018

On April 17, 2018, the cutter suction dredge *Jonathon King Boyd* punctured a submarine natural gas pipeline with a spud during dredging operations in Matagorda Bay, Texas.[166] A gas plume ignited and engulfed the dredge and its accompanying towboat, the *Bayou Chevron*. All 10 crew members abandoned the vessels uninjured.

Investigators found that the dredging company, RLB Contracting, Inc., did not alert the Texas Notification System before commencing dredging near the pipeline. Furthermore, while the *Jonathan King Boyd* crew relied solely on its HYPACK software while conducting dredging operations, RLB Contracting did not incorporate the location of utilities into the software.

The captain and the levermen told investigators that had they known a pipeline was present they would not have allowed the spuds to freefall from their stowed position. Instead, they would have pinned the spud higher and performed a controlled lowering of the spud over the pipeline, if required, to limit the spud's penetration into the channel bottom. The cutterhead would have been secured and the jet pump would have been used when crossing over the pipeline. Also, the dredge would have been repositioned to the other side of the pipeline.

The NTSB determined that the probable cause of the fire aboard the cutter suction dredge Jonathon King Boyd was RLB Contracting's failure to inform the crew about utilities in the area due to ineffective oversight, which led to dropping a spud onto a buried submarine pipeline, causing natural gas to release and ignite.

16.2. Tiger Pass, Louisiana, 1996

On October 23, 1996, in Tiger Pass, Louisiana, the crew of a Bean Horizon Corporation dredge dropped a stern spud into the bottom of the channel in preparation for dredging operations.[167] The spud struck and ruptured a 12-inch-diameter submerged natural gas pipeline owned by Tennessee Gas Pipeline Company. The pressurized natural gas released from the pipeline and

[166] *Pipeline Breach and Subsequent Fire Aboard Cutter Suction Dredge Jonathon King Boyd and Towboat Bayou Chevron, Marine* Accident Brief Report NTSB/MAB-19-19, (Washington D.C., National Transportation Safety Board, 2019).

[167] *Natural Gas Pipeline Rupture and Fire During Dredging of Tiger Pass, Louisiana, October 23, 1996*, Pipeline Accident Summary Report NTSB/PAR-98/01 SUM, (Washington D.C., National Transportation Safety Board, 1998).

enveloped the stern of the dredge and accompanying tug, then ignited, destroying the dredge and tug. No fatalities resulted from the accident.

The safety issues identified in the NTSB report on this accident included, among other concerns, the Tennessee Gas Pipeline Company's practices and procedures for locating, marking, and maintaining markers for gas transmission pipelines through navigable waterways. The NTSB found that Tennessee Gas Pipeline Company took inadequate steps to precisely identify and mark the location of its pipeline through Tiger Pass before dredging operations were undertaken in the pipeline area. Additionally, the NTSB found that had the Research and Special Programs Administration not revoked federal requirements for installing and maintaining markings of pipeline crossings of navigable waterways, the pipeline involved in this accident may have been accurately marked, and the accident may not have occurred.

The NTSB issued the following safety recommendations pertinent to marking pipelines that cross navigable waterways.

To the Tennessee Gas Pipeline Company:

> *Develop formal, written company procedures for identifying the precise locations of your pipelines that traverse navigable waterways before dredging or similar activities are commenced in the pipeline area. P-98-026 (Closed – Acceptable Action).*

To the Research and Special Programs Administration:

> *Require pipeline system operators to precisely locate and place permanent markers at sites where their gas and hazardous liquid pipelines cross navigable waterways. (P-98-25)*

To the Interstate Natural Gas Association of America:

> *Inform your members of the circumstances of the pipeline rupture and fire in Tiger Pass, Louisiana, and urge them to take the actions necessary to ensure that all their pipelines that cross navigable waterways are accurately located and marked (P-98-28)*

To the American Petroleum Institute:

> *Inform your members of the circumstances of the pipeline rupture and fire in Tiger Pass, Louisiana, and urge them to take the actions necessary to ensure*

that all their pipelines that cross navigable waterways are accurately located and marked (P-98-29)

16.3. NTSB Excavation Damage Prevention Safety Study, 1997

In response to concerns about the number of excavation-caused pipeline accidents, the NTSB and RSPA jointly sponsored an excavation damage prevention workshop in September 1994. In 1997, the NTSB published a safety study to analyze the findings from the workshop.[168] The safety issues discussed in the study included:

- Essential elements of an effective excavation damage prevention program,
- Accuracy of information regarding buried facilities, and
- System measures, reporting requirements, and data collection.

Among the findings cited in this study, NTSB stated that pre-marking an intended excavation site to specifically indicate the area where underground facilities need to be identified is a practice that helps prevent excavation damage. According to the study, pre-marking allows the excavators to specifically tell facility owners where they intend to dig. The study noted that some states require the use of white marking to indicate the boundaries of planned excavations.

The NTSB issued the following safety recommendation pertinent to pipeline marking requirements:

Initiate and periodically conduct, in conjunction with the American Public Works Association, detailed and comprehensive reviews and evaluations of existing State excavation damage prevention programs and recommend changes and improvements, where warranted, such as full participation, administrative enforcement of the program, pre-marking requirements, and training requirements for all personnel involved in excavation activity. P-97-15 (Closed – Acceptable Action).

Paul L. Stancil, CHMM
Pipeline Operations Group Chairman
Sr. Hazardous Materials Accident Investigator

[168] *Protecting Public Safety Through Excavation Damage Prevention*, Safety Study NTSB/SS-97/01, (Washington D.C., National Transportation Safety Board, 1997).

List of Attachments

ATTACHMENT 1 –TMI SOLUTIONS SURVEY OF EXISTING PIPELINES, EPIC POCCA TERMINAL, DECEMBER 28, 2018.

ATTACHMENT 2 – APPLICATION FOR U.S. ARMY CORPS OF ENGINEERS DREDGING PERMIT, INCLUDING JACOBS ENGINEERING CONSTRUCTION PLANS DATED MARCH 5, 2019.

ATTACHMENT 3 – SCHNEIDER ENGINEERING EPIC EAST DOCK DREDGING AND CONSTRUCTION PLANS DATED JUNE 23, 2020.

ATTACHMENT 4 – ORION GROUP BULKHEAD ENCROACHMENT PERMISSION REQUEST TO ENTERPRISE PRODUCTS, JUNE 8, 2020.

ATTACHMENT 5 – SCHNEIDER ENGINEERING EPIC MARINE TERMINAL DESIGN/BUILD FOR EAST DOCK, BULKHEAD SITE PLAN, APRIL 9, 2020.

ATTACHMENT 6 – ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS, PHMSA FORM 7000.1, MARCH 2, 2021.

ATTACHMENT 7 – EXCERPT OF ENTERPRISE PRODUCTS PROPANE BATCH TRANSFER RECORD AND PIPELINE PRESSURE HISTORY, AUGUST 21, 2020.

ATTACHMENT 8 – ANNUAL REPORT TO PHMSA FOR CY 2019, HAZARDOUS LIQUID AND CARBON DIOXIDE PIPELINE SYSTEMS, JUNE 11, 2020.

ATTACHMENT 9 – RAILROAD COMMISSION OF TEXAS PERMIT TO OPERATE A PIPELINE, NO. 07403, APRIL 15, 2009.

ATTACHMENT 10 – EXCERPT OF ENTERPRISE PRODUCTS DAMAGE PREVENTION PROGRAM, REQUIRED PIPELINE MARKING LOCATIONS, MAY 4, 2016.

ATTACHMENT 11 – ONE-CALL TICKETS NO. TX1962741283CA AND TX1962741283CB, ENTERPRISE PRODUCTS LINES 124 AND TX219, MAY 7, 2019.

ATTACHMENT 12 – ONE-CALL TICKET NO. TX2067555147CA, ENTERPRISE PRODUCTS LINE 124, JUNE 23, 2020.

ATTACHMENT 13 – ONE-CALL TICKET NO. TX2067555147CB, ENTERPRISE PRODUCTS LINE TX219, JUNE 23, 2020.

ATTACHMENT 14 – EMAIL FROM ORION GROUP PROJECT ENGINEER TO ENTERPRISE PRODUCTS PIPELINE TECHNICIAN, INCLUDING DREDGING PLANS, JUNE 29, 2020.

ATTACHMENT 15 – EMAIL FROM ORION GROUP PROJECT ENGINEER TO DREDGE WAYMON BOYD REGARDING EPIC PIPELINES, JULY 20, 2020.

ATTACHMENT 16 – ENTERPRISE PRODUCTS PIPELINE TECHNICIAN 3 NOTES OF EMERGENCY RESPONSE ACTIONS, AUGUST 23, 2020.

ATTACHMENT 17 – AFFIDAVIT OF ORION GROUP SURVEYOR REGARDING POST-ACCIDENT PIPELINE SURVEY ACTIVITIES, OCTOBER 8, 2020.

ATTACHMENT 18 – AFFIDAVIT OF ORION GROUP SENIOR PROJECT MANAGER REGARDING POST-ACCIDENT PIPELINE SURVEY ACTIVITIES, OCTOBER 8, 2020.

Appendix A: Pipeline Operations Timeline of Events, August 21, 2020

Time	Event	Source
04:26	Pipeline TX219 started to receive a propane batch from Flint Hills Resources. The pipeline pressure increased from its no flow state of about 200 psig to an operating state between 250 and 300 psig as the batch was received.	SCADA Batch no. 75
08:02:49	The pipeline controller received an alarm indicating low pressure at Viola Station. "Value= 156 psi (low state)"	SCADA event logger
08:03	Origin Station Meter 345 registered no flow going through the meter.	SCADA flow meter log
08:04	Viola Station control valve, located downstream of Meter 1004, automatically begins closing. The valve goes from 31.8% open at 08:03 to 23.8% closed at 08:04	SCADA flow meter log
08:05	Viola Station control valve, located downstream of Meter 1004, is closed at the 0% open state. Once this valve closed, the pipeline was isolated at Viola Station, and no more product from Flint Hills could enter Line TX219.	SCADA flow meter log
08:05:19	The pipeline controller received an alarm indicating low-low pressure at Viola Station. "Value = 149 psi (low-low state).	SCADA event logger
08:07	Viola Station Meter 1004 registered no flow going through the meter.	SCADA flow meter log
08:09:12	The pipeline controller telephoned the Enterprise pipeline technician 3 to investigate the low pressure reading at Viola Station Meter 1004. Pipeline technician 3 responded from Origin Station to investigate.	SCADA Center call log
08:15:36	The pipeline controller telephoned the Origin Station pipeline operator at Origin Station and instructed to close the manual valve at Origin Station Meter 345. The Origin Station pipeline operator walked over to the meter and shut it, isolating Line TX219 from propane storage tanks at Origin Station.	SCADA Center call log
08:22	The pipeline controller notified the shift supervisor and control manager that a barge was on fire in the Corpus Christi Ship Channel on fire.	Pipeline Control emergency log
08:31:12	Pipeline technician 3 contacted the pipeline controller from the Viola Station confirming the pressure on the pipeline downstream of the control valve was 131 psig.	SCADA flow meter log; Pipeline Technician 3 August 23, 2020, email to Pipeline Supervisor.
08:32:54	The Origin Station pipeline operator informed the pipeline controller by telephone that the valve at Origin Station Meter 345 had been closed.	SCADA Center call log
08:39:36	The pipeline controller telephoned pipeline technician 3 and they agreed to close motor operated valve MOV-20 at Viola Station to add redundant isolation to the control valve.	SCADA Center call log; Pipeline Technician 3 August 23, 2020, email to Pipeline Supervisor.
08:40*	Pipeline technician 3 received a telephone call from the Corpus Christi pipeline supervisor, who stated he sent the Origin Station pipeline operator to Cantwell Station to close valves isolating Line TX219 from line M4-6. Pipeline technician 3 agreed to respond to Cantwell Station to assist.	Pipeline Technician 3 August 23, 2020, email to Pipeline Supervisor.
08:41:25	The pipeline controller initiated a command to close motor operated valve MOV-20 at Viola Station. SCADA shows the valve completely closed at 08:42:19.	SCADA event logger
08:43:36	Pipeline technician 3 telephoned the pipeline controller and they agreed to also shut down motor operated valve SDV-25.	Pipeline Technician 3 August 23, 2020, email to Pipeline Supervisor.
08:43:49	The pipeline controller initiated a command to close SDV 25 at Viola Station.	SCADA event logger
08:43*	Pipeline technician 3 reported to the Pipeline Controller that the Flint Hills Resources valve site was secure.	Pipeline Technician 3 August 23, 2020, email to Pipeline Supervisor.
08:45:19	SCADA data shows the valve was completely closed.	SCADA event logger
08:51*	Pipeline technician 3 arrived at Cantwell Station to assist the Origin Station pipeline operator close additional valves to provide redundant isolation of Line TX219 from M4-6.	Pipeline Technician 3 August 23, 2020,

		email to Pipeline Supervisor.
09:05:54	The Origin Station pipeline operator telephoned the pipeline controller to inform him the valves at Cantwell Station had been closed to isolate Line TX219 from Line M4-6.	SCADA Center call log
09:47:06	The pipeline controller received a telephone call from a Port of Corpus Christi official notifying of a pipeline fire in connection with a dredging operation.	SCADA Center call log
09:53:06	The pipeline controller telephoned the Corpus Christi pipeline supervisor to report available information about this event.	SCADA Center call log
10:12	Enterprise Products filed a National Response Center report for the incident at 5700 Upriver Road, in Corpus Christi, Texas. Enterprise reported that at 09:54, it was determined that an Enterprise Products pipeline was involved in the incident.	NRC Report 1285164
10:59	Conference call conducted between Enterprise Pipeline Control, Local Operations, Compliance, and Environmental departments.	Pipeline Control emergency log

* Estimated time.