US DOT PHMSA AID Situational Awareness for Employees: SAFE Bulletin[1]
Internal Corrosion – Crude Oil

49 C.F.R. Part 195 Transportation of Hazardous Liquids by Pipeline

Summary: The Pipeline and Hazardous Materials Safety Administration's (PHMSA) Accident Investigation Division (AID) is issuing this SAFE Bulletin to provide inspectors with information about accidents caused by internal corrosion involving releases from crude oil facilities. Facilities for this document include piping and equipment at breakout tanks, storage vessels, terminals, tank farms, pump stations, and meter stations regulated under Part 49 CFR 195. Between January 1, 2010 and August 2020, there were 297-internal corrosion crude oil facility failures. Main line failures are not covered in this document.

The most commonly reported cause, as categorized in PHMSA's hazardous liquid (HL) Accident Report, was microbiological induced corrosion (MIC) (137) followed by water drop-out/acid (106) and corrosive commodity (25)[2]. Localized pitting was evident in almost 70% of the failures. Additionally, nearly all failures occurred at low points in facility piping. Low points are physical or operational dead legs[3]. Relief lines, an operational dead leg, were the item that failed in 5 of the 9 largest HL internal corrosion facility events. In over a third of the failures, operators' internal corrosion control monitoring and prevention measures were ineffective in averting failure. Corrosion coupons were routinely used to monitor internal corrosion in 16 failures. Preventative measures were used in 99 failures: corrosion inhibitors or biocide were used 95 failures, internally coated pipe in 2 failures, and cleaning/dewatering pigs were routinely used to clean the lines in 2 failures. For mitigation measures to be effective, the corrosion mechanism and corrosivity of the commodity for the specific pipe needs to be understood, the corrosion monitored, and the prevention measure periodically reviewed.

Due to the impurities entrained in the commodity, crude oil pipeline systems are at high risk of internal corrosion. Almost 85% of all internal corrosion HL failures occur in crude oil pipeline systems. In addition to main line pipelines, operators are required to cover the threat of internal corrosion in their integrity management program (IMP) for regulated breakout tanks, storage vessels, terminal/tank farms, and pump/meter station equipment and piping when they are in a high consequence area (HCA). Operators must apply appropriate preventative and mitigative

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[1]This bulletin is not intended to revise or replace any previously issued guidance. It is not legally binding in its own right and will not be relied upon by the PHMSA as a separate basis for an affirmative enforcement action or other administrative penalty, and conformity with the bulletin (as distinct from existing statutes and regulations) is voluntary only, and nonconformity will not affect rights and obligations under existing statutes and regulations.

[2] In 52 accidents, the cause field was blank. The field was not required in 2010-2014.

[3] Dead legs are pipeline segments with continuous exposure of a commodity at lower than normal flow rates, at lines intermittently flowing, at stagnant conditions including abandoned pipelines, or at pipelines closed by flanges, welded caps or other fittings. Liquids and solids collect in dead legs and promote internal corrosion.

measures to minimize the possibility of releases in their pipeline integrity plans. AID recommends inspectors review operators' IMP, procedures, maintenance and material records, dead leg management programs, and internal corrosion control program to identify potential deficiencies and areas for improvement.

AID conducts comprehensive data analysis to identify national pipeline incident trends and novel causes. Understanding the consequence of these accidents offers insight in areas for potential improvement to reduce risk and improve integrity management practices. Since January 2010, 297 of the 4,162 (7%) HL reportable accidents involved crude oil releases due to internal corrosion on facility piping. These failures accounted for a total property damage of $109,395,709 and 35,927 barrels of unintentionally released crude oil, of which about 93% were contained on operator-controlled property. There were no injuries, fatalities, evacuations, ignitions or explosions associated with these failures. Soil was contaminated in 228 accidents, wildlife was impacted in 8 accidents, and water was contaminated in 20 accidents.

Sixty-five percent (65%) of the crude oil facility accidents occurred underground, 31% aboveground, and 4% were associated with tanks and transition areas. Most corrosion failures were pinhole leaks in the body of the pipe, and the leaks were identified by ground patrol. Very few were identified by Supervisory Control and Data Acquisition (SCADA).

Additional information in this bulletin includes other causes associated with internal corrosion involving crude oil releases in HL pipelines, correlations of frequency, cost, pipeline operator miles, volume release, and an overview of large accidents.

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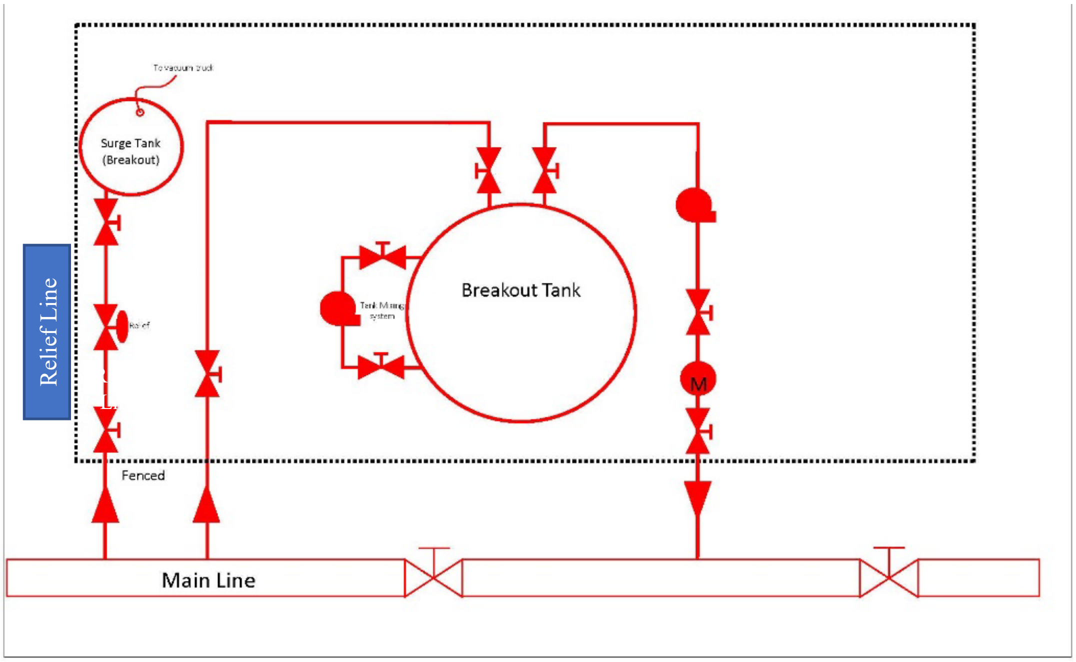
Supplemental Information:

Background

In crude oil facilities, the accumulation of water and the presence of corrosive constituents create environments conducive to internal corrosion. The accumulation of water in the pipeline is influenced by the pipelines' design, the operational conditions, and fluid properties. Fluid properties such as crude composition, entrained gases, entrained water, water chemistry, density, viscosity, thermal conductivity and water wettability, affects how the flow interacts with dead legs and low spots.

Pipeline Design and Operational Condition

Due to their intermittent, low flow, or stagnant use, underground relief lines, strainers, drain lines, valves, meters/provers, by-pass lines, and dead legs may accumulate water in low points. Figures 1 and 2 illustrate examples of operational dead legs. Figure 1 shows a relief line to a surge tank from a main line. The product is stagnant except when the pressure in the main line exceeds the set point on the relief valve and relieves into the surge tank. As shown in Figure 2, drain lines connecting to tanks are another example of a location that is highly susceptible to internal corrosion due to low elevation and intermittent flow.



Pipeline and Hazardous Materials Safety Administration	Flow	Valve	PHMSA	Original Date:	Version Date:
	Pump	Meter		12/13/2013	3/1/2015

Figure 1: Relief Line from Main Line Pipeline to Surge Tank (Breakout)

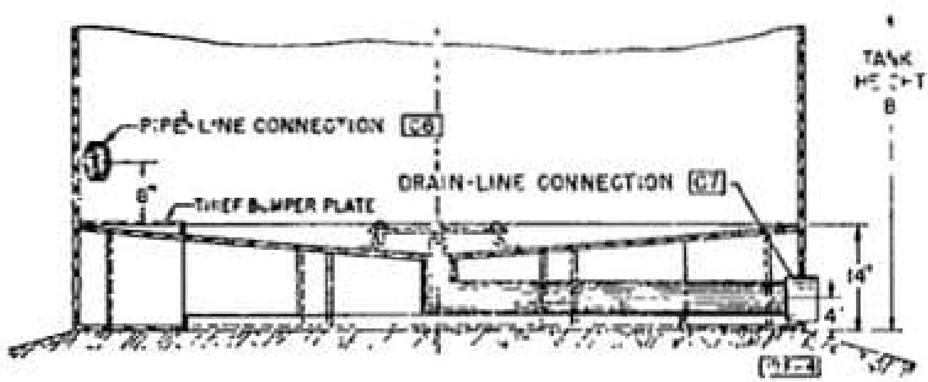


Figure 2: Skirted Cone Bottom Drain-line[4] on Breakout Tank

[4] Photo from website https://res.cloudinary.com/engineering-com/image/upload/v1545855664/tips/hjjjklhjklhjkhkjlhlksadyuiydiuosfhkljfdhaslkjhdkhlf_hlfjdsla_jfdjsalk_jfdksla_jflkd_sajkl_eyuocw.jpg

Corrosive Constituents in Crude Oil

All forms of corrosion in pipelines occur through the action of the electrochemical cell, see Figure 3. In a corrosion cell, electrons flow through a metallic path from sites where anodic reactions (oxidation) are occurring to sites where they allow cathodic reactions (reduction) to occur. Ions (charged particles) flow through the electrolyte to balance the flow of electrons. Anions (negatively charged ions from cathodic reactions) flow toward the anode and cations (positively charged ions from the anode itself) flow toward the cathode. The anode corrodes and the cathode does not. There is also a voltage, or potential, difference between the anode and cathode[5].

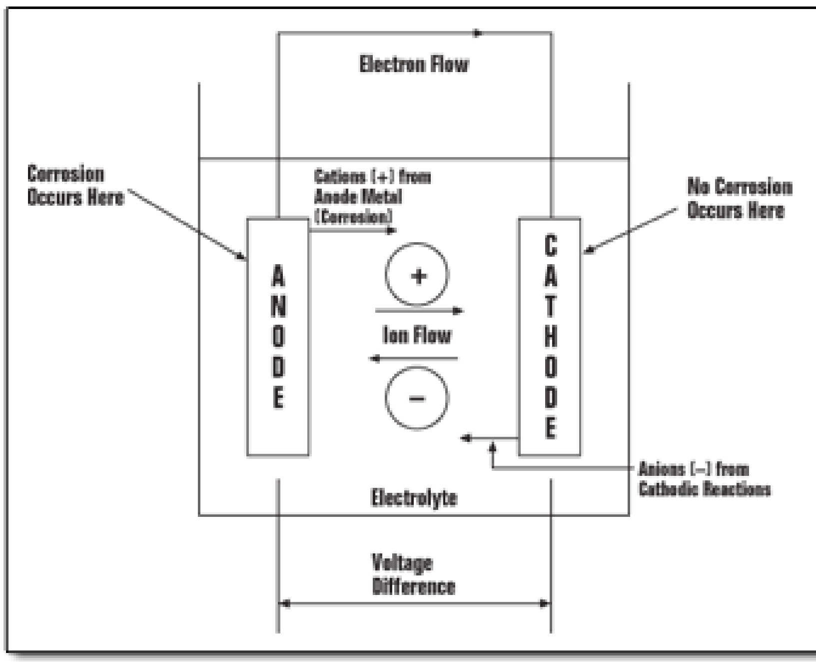


Figure 3 Electrochemical cell[6]

The constituents that may be present in crude oil that promote corrosion are basic sediment and water (BS&W), oxygen (O_2), corrosion causing bacteria, carbon dioxide (CO_2), and hydrogen sulfide (H_2S). The chemistry of the entrained water has a significant impact on the corrosion process due to the concentration of chloride and carbonate ions in the solution.

Sour Corrosion Mechanism - Crude oil often contains considerable amount of H_2S. Crude oil containing a higher percent of H_2S is called "sour crude". Internal corrosion in sour crudes is the result of side reactions of H_2S, H_2O, CO_2, and organic acids. Periodic commodity stagnation produces a build-up of hydrogen sulfide on the metallic surface. These reactions interact with the internal surface of pipelines through anodic and cathodic reactions. Corrosion rates are dependent

[5] Source: NACE International Basic Corrosion Course Handbook, p. 2:9.
[6] https://nace.org/resources/general-resources/corrosion-basics

on the concentration of these products, flow regime, pipeline configuration, operating temperature, oxygen content, the type of metal surface, bacteria, and sediment deposits.

Sweet Corrosion Mechanism - When the corrosive agent is CO_2 and the product contains less than 0.5% sulfur, the crude oil is referred to as "sweet crude". Sweet corrosion or CO_2 corrosion involves the dissolution of the gas in water to form the more reactive species, carbonic acid (H_2CO_3). These species further react producing carbonate ions (CO_3^{2-}), bicarbonate ions (HCO_3^-), and hydrogen ions (H^+) promoting acidic and corrosive solutions. Turbulent flow is often a factor for a sweet system to become corrosive as it prevents formation or removes a protective iron carbonate scale. Corrosion inhibitors are utilized to prevent sweet corrosion.

Sour crude is more common in the Gulf of Mexico and Canada. Texas regional crude basins and the U.S. shale play crudes (Marsalis, Utica, Bakken, Permian, Niobrara) are sweeter crude as compared to other regions. The recent growth in the U.S. crude oil production has been primarily light, sweet crude oil.

Additionally, paraffin in crude oil tends to deposit uniformly along the inside surface of the pipeline, providing protection against internal corrosion. However, water may be deposited in pockets under the wax. Such environments promote pitting corrosion, microbiological induced corrosion (MIC), and under deposit corrosion (UDC). Note: Data about the crude oil composition is not provided on PHMSA's accident reports.

Forms of Internal Corrosion

From a review of technical papers[7], various forms of internal corrosion in HL pipelines are illustrated in Figure 1 and defined below: microbiologically induced corrosion (MIC), pitting corrosion, under deposit corrosion (UDC), galvanic corrosion (PWM and HAZ), stress corrosion cracking (SCC), sulfide stress corrosion (SSC), hydrogen-induce cracking (HIC), and erosion corrosion. For additional information about the forms of internal corrosion, see Appendix A.

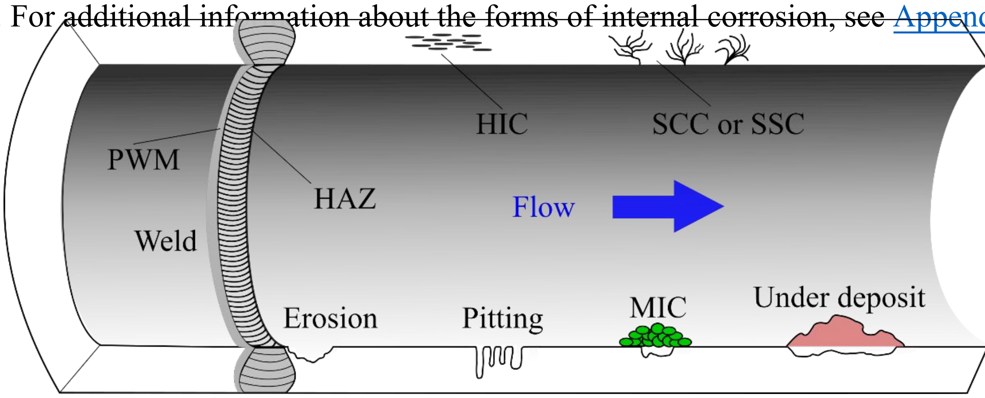


Figure 4. Forms of internal corrosion in a HL pipeline system

[7] See Appendix D - References

<u>Internal Corrosion Preventative Measures and Monitoring</u>

Preventative Measures:

1. *Operational Pigging* – pigging can effectively remove solid deposits, water, sludge, wax or corrosive products if the right pig is used. Following pigging, the removed product should be analyzed to identify threats of internal corrosion. Based on the amount removed, the frequency of the pigging can be adjusted.
2. *Corrosion Inhibitors* – Chemical compounds injected into the pipeline to prevent or minimize corrosion. Inhibitors injected in the main line may not effectively treat facility piping.
3. *Biocides and biostats* – are chemicals used to control microbial growth. Biocides are used to decrease the number of viable bacteria while biostats are used to retard the growth and activity of bacteria. Sometimes they can be the same chemical at different dosages.
4. *Coatings and Linings* – Effective coatings are selected to prevent internal corrosion. Ineffective coatings may effectively concentrate the metal loss at the weld joints.
5. *Redesign* – The pipeline system may need to be redesigned to reduce low spots, eliminate dead legs, and increase flow rates. The selection of different pipeline material and internal coatings may also be selected to prevent internal corrosion.
6. *Operational factors* – factors such as pressure, temperature, pH, type of crude oil, pigging, flow velocity can influence corrosion.
7. *Periodic flushing* - can remove accumulated water and sediment from lines reducing the corrosive effects.
8. *Combinations of these preventative and mitigative measures* - have shown to be highly effective. An effective cleaning pig to remove deposits followed by inhibitors may has been effective in significantly reducing internal corrosion.

Corrosion Monitoring Methods:

1. *Crude Oil Composition and Water Chemistry Sampling* – HLs require analysis for corrosivity before being transported by pipeline. Operators should monitor the hydrogen sulphide, oxygen, BS&W and microbial content.
2. *Direct and Indirect Corrosion Monitoring Surveys* – Internal corrosion monitoring devices can reliably record the corrosive environment inside a pipeline. Placement of the devices in the line is critical to collect meaningful data. Placing a monitoring device in the product stream may provide insight into general corrosion properties of the product, however placing the device in a drop out tube where water can collect will provide information on the corrosivity of the water, sediment and MIC. Corrosion coupons and electric resistance probes are the most common intrusive direct internal corrosion monitoring devices. Additionally, intrusive and indirect methods include bio-probes, Smart Pigging Survey, Linear Polarization Resistance, Electrochemical Noise, and side stream loops.

3. *Residual Chemical Analysis* – to determine the corrosion inhibitor levels in the treatment stream to establish chemical sufficiency. Biocide levels must be applied at sufficient levels to achieve the desired result and must be checked to verify efficacy. If there is MIC, chemical levels should be checked against microbes count. An increase in microbes shows the treatment was ineffective.
4. *Iron Count Monitoring* – Used for monitoring corrosion at different point in the pipeline. High iron count is a warning that the internal corrosion has increased and needs to be controlled. Low count does not necessarily indicate that there is no corrosion.
5. *Sulphate Reducing Bacteria Count* – Of all the microbes, the most implicated in internal corrosion.
6. *Visual Inspection of exposed pipe* – If a passive layer is formed due to corrosion product, the steel surface has become susceptible to internal pitting corrosion.
7. *In-Line inspection (ILI) tools* are commonly used to assess pipelines for areas of metal loss. Operators should review data for accumulation of sediments and gas pockets in addition to corrosion.

Data Analysis of Internal Corrosion

The PHMSA Accident Investigation Division (AID) compiled accident information from HL reportable accidents from 2010 to August 2020. Due to the impurities entrained in the commodity, crude oil pipeline systems are at high risk of internal corrosion. Almost 85% of all internal corrosion HL failures occur in crude oil pipeline systems. Detailed data analysis is in Appendix B.

During the last ten years, 297 of the 4,162 (7%) HL accidents involved crude oil facility releases due to internal corrosion. These failures accounted for a total property damage of $109,395,709 and 35,927 barrels of unintentionally released crude oil, 93% of these spills were contained on operator-controlled property. About half occurred in high consequence areas (HCA). There were no injuries, fatalities, evacuations, ignitions or explosions associated with these failures.

Accidents were identified in 73% of the cases by local operating personnel, including contractors. Spell out SCADA controlled the pipelines in about 70% of the failures, yet only identified 2% of the total number of accidents. Air patrol identified one (1) internal corrosion caused spill.

The majority of the accidents occurred underground (192), which represents 65% of the 297, 31% happened aboveground, and 4% are associated with tanks and transition areas.

The most commonly reported cause, as categorized in PHMSA's hazardous liquid (HL) Accident Report, was microbiological induced corrosion (MIC) (137) followed by water drop-out/acid (106) and corrosive commodity (25). Localized pitting was evident in almost 70% of the failure and general corrosion in about 12% of the accidents. Additionally, nearly all failures occurred at low points in facility piping as they were physical or operational dead legs. Relief lines, a type of operational dead leg, were the item that failed in 5 of the 9 largest HL internal corrosion facility events.

In over a third of the failures, operators' internal corrosion control monitoring and prevention measures were ineffective in averting failure. Corrosion coupons were routinely used to monitor internal corrosion in 16 failures. Preventative measures were used in 99 failures: corrosion inhibitors or biocide were used 95 failures, internally coated pipe in 2 failures, and cleaning/dewatering pigs were routinely used to clean the lines in 2 failures. For mitigation measures to be effective, the corrosion mechanism and corrosivity of the commodity for the specific pipe needs to be understood, the corrosion monitored, and the prevention measure periodically reviewed.

The averages per accident for total property damage and unintentional volume spilled is $368,336 and 121 barrels respectively. The maximum and minimum are $17,500,000, $200 and 5,700, 0.02 barrels respectively.

Results of the number of internal corrosion failures per decade of installed pipe are shown in Figure 3. From the 126 accidents with this information, 36% of those had pipe installed in the decades of 1910-1950, 20% in the decades of 1960-1980 and 44% in the last thirty years (1990-2020).

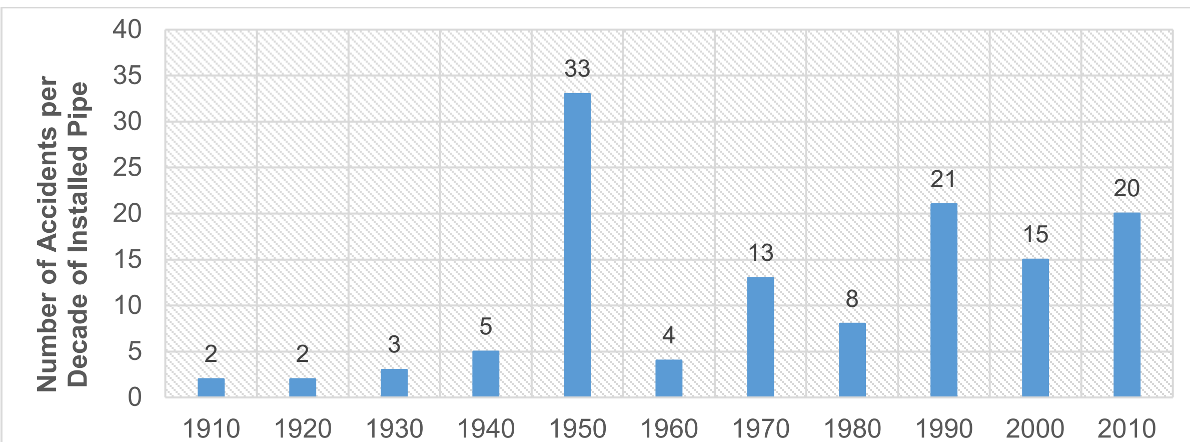


Figure 5. Number of accidents per decade of installed pipe.

Contributing Factors of Internal Corrosion Failures

AID found common contributing factors of internal corrosion failures included: poor maintenance of relief lines; intermittent, low flow or stagnant lines connecting tanks; inadequate treatment of corrosive commodity; water accumulation in traps; oxygen-rich environments; lack of corrosion monitoring techniques; ineffective use or insufficient quantity of inhibitors or biocides; and the precipitation or accumulation of solids. Additional details from the narratives in the accident reports are characterized and summarized below.

Poor Maintenance of Relief Lines

- Approximately 40 barrels of crude oil were released from a 24-in carbon steel aboveground pipeline. The failure was discovered by a ground patrol technician. Excavation identified the leak originated from the bottom of a pipeline. A PLIDCO clamp was installed to repair the pinhole. The crude oil was contained inside the dike wall. Contaminated soil was removed and the total property damage reached $400,000. The segment was placed into quarterly dead leg flush program to prevent recurrence.

- An operator technician identified crude oil on the ground at the station and notified pipeline control to shut down the line due to a possible leak. The leak was confirmed to be coming from a 20-inch relief line. The ¾-inch hole released 300 barrels of crude oil with 50 barrels reaching groundwater. Ultrasonic testing at the leak source determined the cause to be localized corrosion. The engineering group recommended the replacement of the line with an aboveground section. Property damage costs reached $400,000.
- Pipeline control received a call from operations at a tank farm reporting a ditch full of oil. The controller stopped all pumps and shut down the delivery. Two lines were suspected to be the source of the leak. Field operations confirmed the release of 100 barrels of crude oil from a 12-inch relief system. The line is normally static (no flow) and does have tank head pressure on it. A pinhole was found at the 6 o'clock position. The hole was plugged, and a PLIDCO sleeve was installed, and a pumpkin enclosure was welded onto the pipe enclosing the sleeve. The operator is evaluating the injection of an inhibitor to mitigate any corrosion from happening again since this line was not previously treated.

<u>Intermittent, Low Flow or Stagnant Lines</u>

- A small pinhole leak was discovered in a side valve connection for bypass piping. Stagnant conditions led to localized corrosion at the bottom of the pipe releasing one gallon of crude oil. This branch connection had been previously blinded and placed out of service, but not eliminated from the system. The damaged was replaced with a straight section without the valve attachment. The operator is reviewing similar connections in the facility to prevent this issue from happening again. Total property damage was $96,000.
- Operator technicians discovered oil in a retention pond at the crude oil terminal. The control center was immediately notified and all the pipelines in the vicinity were shutdown. Once the piping was isolated and soil removed, the segment was removed and sent to a metallurgical laboratory for failure analysis. Results from this analysis revealed that the failure was most likely caused by a combination of microbes, oxygen and the line segment being static. The total amount released was 225 barrels of crude oil.

<u>MIC</u>

- Localized pitting was found in several places inside the pipe at 3:00 and 5:00 o'clock positions. The pinhole released 718 barrels of crude oil. MIC was caused by no movement through the 20-year-old 6-inch underground pipe for approximately 4 years. The pipe was purged and abandoned with total property damage of $82,000.

- Approximately 95 barrels of crude oil were released within a secondary containment due to internal corrosion on a tank line. A pinhole leak was discovered at the 6 o'clock position and was repaired with a clamp. The results of the failure analysis indicated that the leak was associated with a discrete pit and was located within an area of accumulated solids. Corrosion likely occurred within the pipe during periods of stagnation and microorganisms played the primary role in the corrosion mechanism.
- Soil discoloration was discovered by an operator's technician during a routine terminal inspection in a tank farm. Excavation of the area revealed a pinhole at the 6 o'clock position of an under-utilized section releasing 28 barrels of gasoline. This 12-inch carbon steel underground pipe segment was purged, disconnected, partially removed and discontinued from service. Laboratory results found that MIC was the cause of the leak. The pipe had low flow characteristics with no treatment by inhibitors or biocides.
- One barrel of crude oil was released within a secondary containment from an 8" pipeline which supplies a tank manifold. The third-party analysis indicated that the leak occurred due to internal corrosion that propagated through-wall at the 6:00 o'clock orientation. The leak was associated with a discrete pit that was covered with deposits and likely caused by MIC with a possible contribution from CO_2. To prevent further releases, ultrasonic testing has been conducted through the manifold, and similar design piping has been removed from the manifold.

<u>Water Accumulation in Traps</u>

- A branch line leak on a pump discharge header released 240 barrels of crude oil. The dead leg section developed localized corrosion due to water present in the pipe. 48 cubic feet of soil were contaminated and the dead leg was removed from the system.
- An operator's technician discovered crude oil leaking during a routine facility inspection. Internal corrosion led to the failure of the 16" tank fill line with a pinhole at the 6 o'clock position. Original design of piping allowed water/sediments to be trapped in the low point of the piping. Corrective actions included the redesigned and replacement of the manifold piping.
- Approximately 4 barrels of crude oil were released from a pinhole leak at the 6 o'clock position. The 24-inch aboveground manifold tank line failed due to water/sediments dropout.

<u>Lack of Corrosion Monitoring Techniques</u>

- During a routine site inspection, local operations identified crude oil on the ground near a storage tank manifold system. The system was shut down and the area was excavated. It was discovered that the manifold contained an unknown dead leg with a leaking flange. The dead leg piping was removed from service by installing a blind flange to prevent further leaks. The operator established an on-going awareness program to identify potential dead leg sources to prevent any future leaks. The total amount released was 60 barrels.

Inadequate Treatment of Corrosive Commodity

- A localized pitting pinhole was discovered in an underground carbon steel 2-inch relief line releasing 29 barrels of crude oil. The metallurgical analysis report concluded that the most probable cause of the failure was due to carbonic acid corrosion from carbon dioxide dissolved in water. This line operated at low flow, was not treated with inhibitors or biocides, and accumulated water in the low point of the segment.
- During a routine facility inspection, a technician discovered a crude oil leak. Approximately 2 barrels of crude oil were released because of a pinhole leak, located in the 6 o'clock position, on an infrequently used, subsurface bypass line, initiated by internal corrosion. Metallurgical analysis concluded that the leak was due to the presence of CO_2 and H_2O in the pipe, a byproduct of the idle crude oil. The internal surface was covered with reddish brown deposits, shown to be iron oxide. This section of pipe was deemed unnecessary for operation and removed.
- Approximately 173 barrels of crude oil were released, within a vault, due to a pinhole leak in the 6 o'clock position. One barrel of oil reached a storm drain system. The metallurgical examination determined that the pinhole was a result of aqueous internal corrosion from a combination of CO_2 and saltwater that collected in a low point of the line. In addition to replacing this section with internally epoxy-coated pipe, a new flange and fitting, the operator plans to perform regular deliveries of product through this segment to assist with flushing the line.

Major Internal Corrosion Accident Investigations at Crude Oil Facilities

The Summary of 9 Internal Corrosion Events at Crude Oil Facilities are in **Appendix C**.
Below is a characterization of the 9-crude oil, facility accidents failure due to internal corrosion with the largest volume released from for the 10-year period.

- Release volume ranged from 900 to 5,600 barrels.
- All accidents were on underground pipes or vessels
- Pipeline diameters 2-12-inch, 1-16-inch, 1-20-inch, 2-24-inch, 1-36-inch, 1-strainer
- 8 leaked and 1 ruptured
- Age of pipe/vessel was from 5-35 years old
- 4 events occurred at >20% SMYS. Pressure did not exceed MOP in any failures.
- SCADA was in place in 7 facilities and detected 2 of the leaks.
- Relief lines were involved in 5 of the 9 events. Three were in service less than 10 years.
- Some leaks were on tank lines at head pressure and piping did not contain check valves.
- Some of the leaks were on large diameter pipe at higher pressures.
- 4 facilities used corrosion inhibitors.
- None of the facilities used corrosion coupons or ILI.

Regulatory Requirements for Internal Corrosion Control and Integrity Management
Internal corrosion is subject to corrosion control CFR 49 Part 195, Subpart H, 195.579(a)(b)(c)[8], 195.585[9], 195.587[10], 195.589(c)[11], 195.591[12]. Additionally, pipeline integrity requirements follow §195.452[13].

§195.579 What must I do to mitigate internal corrosion?

Under §195.579(a), operators must take adequate steps to mitigate internal corrosion when transporting corrosive products. In addition to understanding corrosive crude oil constituents, operator procedures may benefit from identifying the factors that influence the formation of internal corrosion, paying special attention to environment created by the pipeline design such as changes in elevation, low points, sharp bends and dead legs that allow BS&W and paraffin to settle out.

Under §195.579(b), any operator using inhibitors to mitigate corrosion, must (1) use sufficient quantity, (2) use corrosion coupons to determine the effectiveness of the inhibitors, and (3) examine the coupons twice a year, Operators should pay attention to specific conditions including flow characteristics and pipeline configuration, (i.e. areas that may not be flushed or cleaned by pigging such as station piping, relief lines, drains, dead legs, meters/provers, sags, and overbends).

> Advisory Bulletin: ADB-08-08[1] reminds operators of their responsibilities under §195.579(a) and §195.589(c) with respect to the identification of circumstances under which the potential for internal corrosion must be investigated.

Under §195.579(c), the operator must inspect any pipe removed from the pipeline for internal corrosion. If the internal corrosion meets the requirements under 195.585, they must determine the extent of the additional corrosion near the removed pipe and take remedial actions.

195.452 Pipeline integrity management in high consequence areas

Section 195.452 applies to pipelines in High Consequence Areas (HCAs). While Inspectors have familiarity with operators' main line pipe inspection programs, internal corrosion programs must address specific threats within the facility. Facilities within HCAs or that have the potential to affect HCAs, require a facility integrity management program. These facility programs are required to identify the threats to piping integrity, this includes internal corrosion. Operators must

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[8] §195.579 What must I do to mitigate internal corrosion?
[9] §195.585 What must I do to correct corroded pipe?
[10] §195.587 What methods are available to determine the strength of corroded pipe?
[11] §195.589 What corrosion control information do I have to maintain?
[12] §195.591 In-Line inspection of pipelines
[13] §195.452 Pipeline integrity management in high consequence areas

have a written procedure to identify the locations of dead legs, low flow and intermittent flow piping to implement preventative and mitigative measures.

§ 195.585 What must I do to correct corroded pipe?

If the remaining wall thickness is less that required for the MOP, the pipe must be replaced, repaired, or pressure reduced to commensurate with the strength of the remaining pipe. Methods to determine the strength of corroded pipe are in § 195.587.

§195.589 What corrosion control information do I have to maintain?

Operators are required to maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test to demonstrate adequacy of corrosion control measures.

§ 195.591 In-Line inspection of pipelines.

When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API Standard 1163, Inline Inspection Systems Qualification Standard; ANSI/ASNT ILI-PQ, Inline Inspection Personnel Qualification and Certification; and NACE SP0102-2010, Inline Inspection of Pipelines (incorporated by reference, see §195.3). An in-line inspection may also be conducted using tethered or remote control tools provided they generally comply with those sections of NACE SP0102-2010 that are applicable.

AID Recommendations for Inspectors

Internal corrosion in crude oil facility occurs at discrete sites due to deviations in the metallurgical, chemical and physical properties of these sites. Localized corrosion is a difficult process to identify and mitigate because it is dynamic. Despite these challenges, to mitigate internal corrosion, the pipeline system should be designed to reduce low spots, dead legs and increase flow rates. Operators should review dead leg management program and include: 1) review dead leg use and inspection frequency, 2) conduct a review for proper decommissioning and purging or abandoned piping, and 3) redesign which may entail adding a blind, using tight shutoff valve or installation of double block and bleed.

API 581 Risk-Based Inspection Technology covers assessing the risk of a dead leg and provides a constant adjustment factor for a corrosion rate for the thinning damage factor. Unfortunately, this assumption is not applicable to the dead leg section unless a level of confidence can be gained through inspections or corrosion coupons. Sayed's paper, *Proposed Guideline for Identification and Assessment of Dead Legs,* provides a case study of a dead leg assessment based on a risk based approach using the predicted maximum corrosion rate of a dead leg section against the maximum corrosion rate of the main line piping to which the dead leg is connected.

Where possible accumulation of solids may occur, operators should consider the use of internal coatings, effective cleaning by routine pigging, and establish integrity plans for the use of inhibitors or biocides. For station piping that cannot be in-line inspected, the common mitigation methods are internal monitoring probes, routine flushing, displacing crude oil in relief lines with refined product, installation of check valves, periodic ultrasonic testing (UT), and the removal of dead legs.

AID recommends that inspectors evaluate the operator's internal corrosion control program to ensure that major corrosion risk parameters are being monitored, analyzed, and recorded to conform with the requirements of §195.589(c). The code instructs operators to maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist.

The NACE standard SP0106-2018 [23], Control of Internal Corrosion in Steel Pipelines and Piping Systems, provides recommended practices for the control of internal corrosion on HL lines.

A successful of an internal corrosion program may include the following information:

- Mechanisms of corrosion.
- Operational factors influencing corrosion such as pressure, temperature, pH, flow velocity and salt content.
- Monitoring of corrosion through devices and tests, including analysis of gas, liquid and sludge/solid samples, coupons, and electrical probes.
- Techniques and methods of evaluation of evidence to determine the root cause of corrosion through examination of exposed surfaces.
- Selection of mitigation methods such as chemical treatment by biocides and/or corrosion inhibitors
- Maintenance of the pipeline system including the use of cleaning pigs, clearing drips, and clearing valves.
- Use of internal coatings on critical areas likely to accumulate solids or corrosive media.
- Facility design considerations.
- Integrity assessment methods including internal corrosion direct assessment, ILI, and hydrostatic pressure testing.

Based on lessons learned from accidents, an analysis of the following records could help identify potential safety-related conditions from internal corrosion:

- Maintenance records of relief lines, intermittent, low flow or stagnant lines connecting tanks

  - Identify the location of underground and aboveground segments to characterize the environment of exposure.
  - Methods of leak detection or monitoring. Active leaks from pinholes can go undetected for a long time due to small leak rates.
- Corrosion control mitigation plans including:
  - Corrosion monitoring techniques.
  - Effectiveness tests of inhibition and biocide use.
  - Treatment methods of corrosive media.
  - Identification of water accumulation or traps.
- Design considerations in facilities including the following:
  - Use of smaller pipe diameter to maintain high flow rates.
  - Pipeline segments designed to accommodate ILI and cleaning tools.
  - Installation of pig launchers and receivers.
  - Installation of corrosion monitoring and sampling points.
  - Process equipment, such as scrubbers for the removal of hydrogen sulfide or carbon dioxide, separators, filters, and dehydration units, drips or other liquid accumulation sites.
  - Elimination of dead legs and/or abandoned assets.
- Previous accidents involving internal corrosion failures
  - Did the operator establish a program to identify and manage the key factors contributing to internal corrosion?
  - What were the corrective actions established to avoid future releases?

Evaluate the operator's integrity assessment program to identify if the operator has identified pipelines that are or have been exposed to potential risks of internal corrosion, and if there are operating conditions where a pipeline could remain stagnant for extended periods.

To gain an understanding of what causes internal corrosion and how to prevent future incidents, a procedure describing how internal corrosion investigations are conducted needs to be in place. From a regulatory standpoint, certain parts of this procedure may apply to the operator while other parts may describe the actions from State and Federal responders. It is crucial to ensure that key information is not overlooked.

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Appendix A – Forms of Internal Corrosion at Crude Oil Facilities

- **Localized Internal Corrosion –** localized corrosion is a concentrated attack in confined areas while the general surface corrodes at a much lower rate. Localized corrosion is caused either due to an inherent property of the component material (such as the formation of a protective oxide film) or because of an environmental effect. Forms of localized corrosion include:
    - **Pitting corrosion** initiates where there is a breakdown of the nanometer thin passive film. The remainder of the passive film acts as the cathode and the pit is the anode. Pitting corrosion always occurs due to the existence of an aggressive anion, such as a chloride ion (Cl^-). The growth rate can be very high or, in some conditions, re-passivation is restored and the corrosion stops. The pitting corrosion rates and location are difficult to predict as the properties of the surface films are not well-comprehended, difficult to measure on a small scale, and alter continuously with time. Pitting can be difficult to identify because isolated pits can be small in diameter but deep, and are sometimes covered with deposits or corrosion products that have some magnetic permeability which can mask the wall loss to a magnetic flux leakage (MFL) signal.
    - **Crevice corrosion** – occurs when a portion of a metal surface is shielded from the surrounding environment and usually associated with a stagnant solution on a micro-environmental level. The corrosion cell is formed between the unshielded surface and the crevice interior exposed to the environment with a lower oxygen concentration compared with the surrounding medium. **Under-deposit Corrosion (UDC)** is a form of crevice corrosion. UDC usually occurs at the 6 o'clock position of a pipe beneath layers of debris, scale, biofilm or corrosion products. In this concentration, the environment exists that is favorable for many types of corrosion to occur including MIC and galvanic corrosion.

> PHMSA accident report indicates if Results of Visual Examination are *Localized Pitting, General Corrosion, Not Cut Open, or Other*.
>
> Cause of Corrosion include: *Corrosive Commodity, Water drop-out Acid, Microbiological, Erosion and Other.*

- **MIC** refers to corrosion caused by the presence and activity of microorganisms on metal surfaces by adhering biofilms. Underneath these colonies, localized corrosion is initiated. The presence of microorganisms does not translate into the development or occurrence of corrosion, but must be considered as a factor along chemical and physical conditions.

  Microorganisms find essential nutrient conditions to thrive around carbon sources, including hydrocarbons, fatty acids, and other fermentation products distributed across the transportation of crude oil systems. Furthermore, design features and operating conditions may create zones with different flow regimes, such as dead legs, limiting the access of such nutrients. Higher flow rates increase the supply of nutrients, and may result in the removal of biofilm.

Microorganisms with conductive characteristics may use iron as their source of energy under starving conditions.

- **Galvanic corrosion** is also referred to as dissimilar metal corrosion. The susceptibility to encounter internal galvanic corrosion in pipelines is may occur in or near welds. Preferential weld metal (PWM) corrosion refers to the anodic behavior of the weld metal and/or heat affected zone (HAZ) and the influence of its chemical composition with the base metal. The potential difference may be enough to form a galvanic cell and cause corrosion. HAZ is adjacent area to the weld, and experienced various temperatures during the welding process, forming a wide range of microstructures between the fusion line and the base metal making allowing this area to be susceptible to corrosion. These types of failures have been seen in low frequency electric resistance welded (LF ERW) pipe. Selective seam weld corrosion (SSWC) is an example of galvanic corrosion. SSWC rarely occurs internally but is more common externally[14]. Long seams located at the 6 o'clock position increases the susceptibility to SSWC. There were 119 HL galvanic external corrosion accidents, 1 HL pipeline galvanic internal corrosion accident, but no crude oil facility galvanic internal corrosion accidents.
- **Erosion corrosion** is the mechanical degradation of the metal surface caused by impinging liquid carrying abrasive particles, suspended particles, bubbles or droplets, or cavitation. Erosion corrosion can also be the results of irregular weld deposit shapes that promote turbulent flow.
- **Environmental Cracking-Related** failures may be linked to corrosion and corrosion-control processes. PHMSA Accident forms categorize environmental cracking-related events under cause G5- Material Failure of Pipe or Weld instead of G1 Corrosion Failure. Subtypes of environmental cracking include hydrogen-induced cracking, stress corrosion cracking and sulfide stress corrosion. There were 2 crude oil facility and 4 crude oil main line pipe accidents reported as caused by environmental cracking. All cracking appeared on the exterior of the pipe.
    - **Hydrogen-induced Cracking** (HIC), also referred to as hydrogen embrittlement corrosion, is linked to cathodic protection processes. The ingress of hydrogen atoms into a metal substrate tend reduces the ductility and load-bearing capacity of the material. The result is stepwise cracking and stress-oriented hydrogen induced cracking, and brittle failures below the yield stress of the material. HIC is observed in high-strength steels.
    - **Stress Corrosion Cracking** (SCC) is induced by the combination of tensile stress and the presence of hydrogen and sulfur in a low corrosive environment. SCC is characterized by fine cracks coalescing which lead to failure. NACE MR0175 standard

[14] https://kiefner.com/selective-seam-weld-corrosion-how-big-is-the-problem/

provides the definition of SCC/HIC conditions (pH vs. H2S partial pressure), including guidelines for material selection.

- **Sulfide stress corrosion** (SSC), is a type of SCC. Like HIC, it is also a form of hydrogen embrittlement due to the absorption of hydrogen produced by the wet H_2S corrosion process. Susceptible steels react with hydrogen sulfide and form metal sulfides and atomic hydrogen as corrosion byproducts.

Appendix B -Data Analysis of Internal Corrosion at Crude Oil Facilities

The PHMSA Accident Investigation Division (AID) compiled accident information from HL reportable accidents[15] from 2010 to August 2020. Information on internal corrosion failures was collected from Part G: Apparent Cause, G1: Corrosion, and Sub-Cause: Internal Corrosion in Form PHMSA F 7000-1. Data was refined by searching for only Crude Oil failures under A8: Type of Commodity Released = Crude Oil; and C2: Part of System Involved in Accident to exclude Offshore Pipeline, Onshore Pipeline Including Valve Sites, and Tanks but to include tank piping.

During the last ten years, 297 of the 4,162 (7%) HL accidents involved crude oil facility releases due to internal corrosion. These failures accounted for a total property damage of $109,395,709 and 35,927 barrels of unintentionally released crude oil, 93% of these spills were contained on operator-controlled property. About half occurred in high consequence areas (HCA). There were no injuries, fatalities, evacuations, ignitions or explosions associated with these failures.

Accidents were identified in 73% of the cases by local operating personnel, including contractors. Spell out SCADA controlled the pipelines in about 70% of the failures, yet only identified 2% of the total number of accidents. Air patrol identified one (1) internal corrosion caused spill.

The majority of the accidents occurred underground (192), which represents 65% of the 297, 31% happened aboveground, and 4% are associated with tanks and transition areas.

The corrosion cause and examination method is shown in the following table:

Q8. The causes(s) or corrosion selected in Q7 is based on the following	Field Examination	Metallurgical Analysis	Other	Total
Microbiological	101	37	15	153
Water Drop-out/acid	86	25	9	120
Corrosive Commodity	17	8	10	35
Erosion	2	1	0	3
Other	10	11	6	27
Total	216	82	40	338

Note that under this internal corrosion category, some records left Q8 field blank since the field was not required from 2010 to 2014. Some accidents had a field examination and metallurgical analysis so the total number of examinations is greater than the total number of accidents. The results of visual examination showed localized pitting in about 70% and general corrosion in about 12% of the accidents.

[15] Accident Report - Hazardous Liquid Pipeline Systems Form PHMSA F 7000-1 (CFR Title 49, §195.54)

The location of the corrosion also includes multiple selections. From a review of the narratives, nearly all failures occurred at the low point of the pipe or appurtenance.

Q9. Location of Corrosion	
Low point in pipe	184
Elbow	16
Other	54
Blank	53
Total	307

Of interest, operators provided the "Other" location of the corrosion as:

SUCTION PIPELINE STRAINER; WITHIN STRAINER HOUSING
NPS 2 WELD-O-LET
3 instances - METER CASING: BUSHING WAS INSTALLED ON LOW POINT OF METER CASING TO ALLOW DRAINING FOR REPAIRS
3 instances - ON A VALVE; 2 - FLANGE NECK OF VALVE; ON THREADS OF VALVE BODY BLEED PLUG; SIDE VALVE CONNECTION FOR BYPASS PIPING; NEEDLE VALVE ON CORROSION INHIBITOR SLED
AREA OF MANIFOLD THAT WAS NO LONGER USED AND PRODUCT FLOW DID NOT OCCUR.
BOTTOM OF HOLDER
FABRICATED TEE; MANUFACTURED BEND
1/2" PLUG AT 12:00 POSITION
PUMP DISCHARGE FLANGE
BOTTOM OF HOLDER

In 95 internal corrosion reports corrosion inhibitors or biocides were in use. In 150 reports, inhibitors or biocides were not used. The following table shows the system part involved, and if corrosion inhibitors were used.

	CORROSION INHIBITORS USED?		
System Part by Item Involved	**NO**	**YES**	**Total**
ONSHORE BREAKOUT TANK OR STORAGE VESSEL, INCLUDING ATTACHED APPURTENANCES			
PIPE	5		5
TANK/VESSEL	1	1	2
FLANGE	1		1
RELIEF LINE	1		1
Total	**8**	**1**	**9**
ONSHORE PUMP/METER STATION EQUIPMENT AND PIPING			
PIPE	24	20	44
AUXILIARY PIPING (E.G. DRAIN LINES)	1	4	5

METER/PROVER		4	4
VALVE	1	2	3
WELD, INCLUDING HEAT-AFFECTED ZONE	1	2	3
RELIEF LINE	1	1	2
FLANGE		1	1
PUMP	1		1
TUBING	1		1
OTHER	1	3	4
Total	**31**	**37**	**68**
ONSHORE TERMINAL/TANK FARM EQUIPMENT AND PIPING			
PIPE	80	45	125
AUXILIARY PIPING (E.G. DRAIN LINES)	12	4	16
RELIEF LINE	9	2	11
VALVE	2	3	5
WELD, INCLUDING HEAT-AFFECTED ZONE	4		4
FLANGE		1	1
METER/PROVER	1		1
OTHER	3	2	5
Total	**111**	**57**	**168**
Grand Total	**150**	**95**	**245**

In two reports the pipe was internally coated, two used cleaning/dewatering pigs, and 16 used corrosion coupons.

The averages per accident for total property damage and unintentional volume spilled is $368,336 and 121 barrels respectively. The maximum and minimum are $17,500,000, $200 and 5,700, 0.02 barrels respectively.

Table 1 shows a breakdown of the total property damage and barrels spilled per year. Results from this analysis show the influence of outliers such as the release in 2012 of 900 barrels of crude oil with costs over $9,000,000 in Mokena, Illinois. In 2013, the release of 5,600 barrels of commodity exceeding costs of $3,000,000 in Magnolia, Arkansas; and the release of 2,242 barrels of crude oil in Cushing, Oklahoma with total damages reaching more than $13,000,000. A fourth outlier was the failure in Belle Chasse, Louisiana in 2019 where 1,195 barrels of crude oil were released and costs reached more than $8,000,000.

The highest number of accidents during the 10-year period occurred in 2014 and 2015 with 35, which is 30% higher than the determined mean. The average for the 10-year period is 27 accidents per year.

Table 1. Total cost and total barrels spilled per year.

Year	Number of Accidents	Property Damage	Barrels Spilled
2010	26	$1,953,867	736
2011	28	$17,136,212	1,486
2012	33	$15,344,304	4,100
2013	21	$25,001,267	8,582
2014	35	$7,203,035	2,547
2015	35	$5,545,464	2,539
2016	31	$3,011,318	1,642
2017	28	$6,174,667	3,520
2018	21	$7,256,754	6,191
2019	28	$15,279,164	3,433
2020	11	$5,489,657	1,152
Total	**297**	**$109,395,709**	**35,928**

Figure 2 shows the trend-cycle of accident history from 2010 to 2019 by using the 3-year moving average method to eliminate the influence of outliers in the dataset. The trend of accidents from 2010 to 2020 is relatively flat. In the last ten years, the number of crude oil pipeline miles in the continental U.S. increased 53%.

This graph reflects the normalization of the data by miles of pipe against the number of accidents per year. This shows that accidents of this type are decreasing relative to miles of pipe.

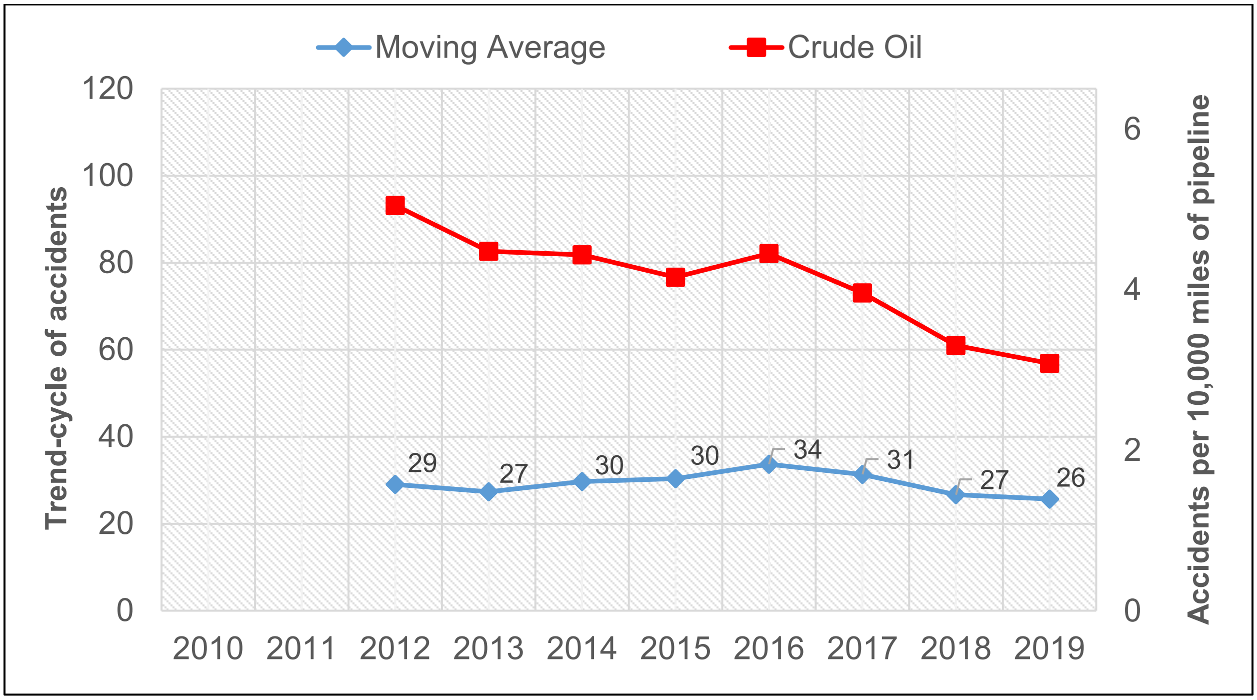


Figure 6. Trend-cycle of internal corrosion accidents and trend of crude oil from 2010 to 2019.

The total property damage and barrels spilled for each internal corrosion sub-cause type is shown in Table 2. Accidents due to MIC are the most prevalent, accounting for 46% of the total number of accidents in the 10-year period, followed by water drop/acid with 36% of the total number of accidents, 8% by corrosive commodities, and 9% caused by other mechanisms. 'Pinhole' was the main leak type associated with internal corrosion failures (86% of the total number of accidents).

Table 2. Total property damage and barrels spilled for each sub-cause type due to internal corrosion by dead legs from 2010 to Present.

Sub-Cause Type	Number of Accidents	Total Damage	Barrels Spilled
MIC	137	$81,635,769	20,113
Water drop/Acid	106	$27,625,591	10,624
Corrosive Commodity	25	$6,785,543	7,034
Other	27	$12,565,048	4,309

Results of the number of internal corrosion failures per decade of installed pipe are shown in Figure 3. From the 126 accidents with this information, 36% of those had pipe installed in the decades of 1910-1950, 20% in the decades of 1960-1980 and 44% in the last thirty years (1990-2020).

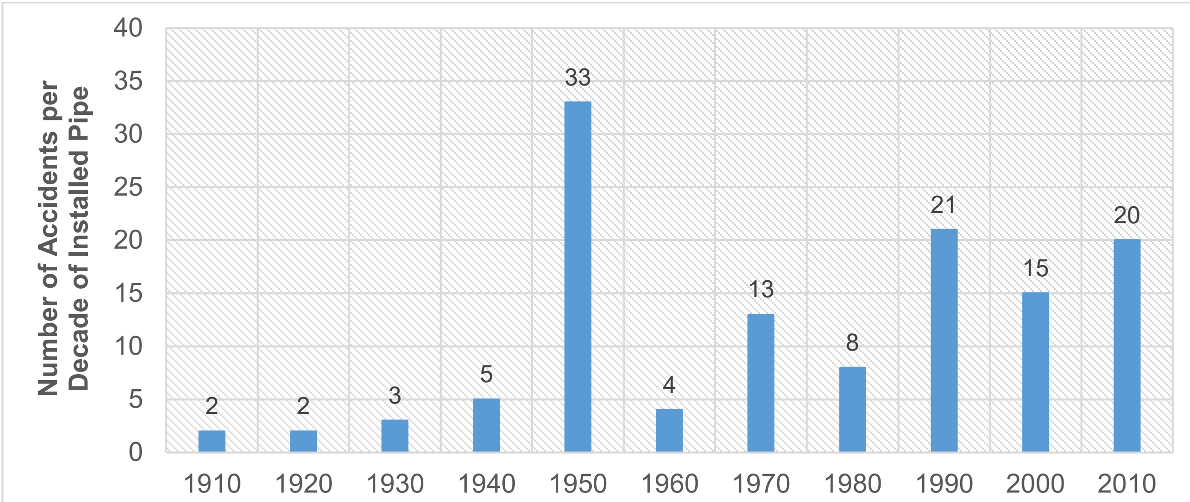
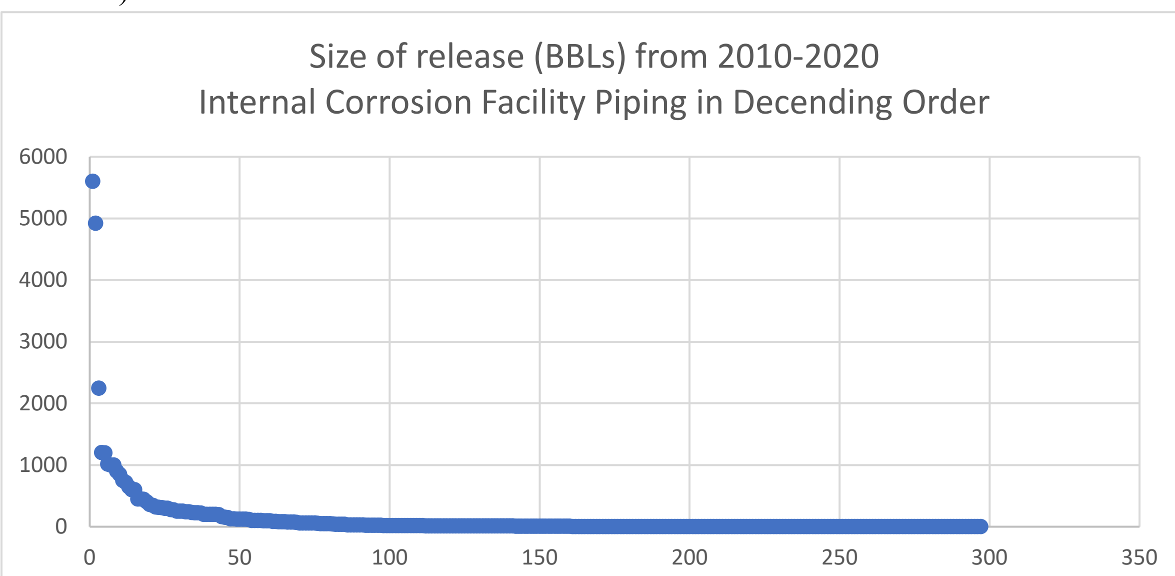


Figure 7. Number of accidents per decade of installed pipe.

Most accidents had small unintentional releases as shown in the figure below (Size of release vs. instances).



Appendix C – Accident Narratives

Accident 1 – #20190328 - Belle Chasse, Louisiana 2019 (1,195 barrels) – Relief Line

In October 2019, a leak was detected in a 12-inch relief line downstream of the relief valve, releasing 1,195 barrels of crude oil at a breakout tank at a refinery. The pressure at time of failure was 12.5 psig. The crude was difficult to identify by walk arounds until it was visible in the underground drain in the tanks' containment area. The operator confirmed the loss of liquid level in two tanks, which share the same relief line. They found a stream of product continuing to flow from a spot underground to a drain valve in the tanks' containment area. Additionally, the dike wall was compromised by a broken valve stuck slightly open and product was also able to escape to the operator's nine-acre property where it impacted local wildlife (birds). The pinhole leak was caused by MIC at the 6 o'clock position. The total property damage for this accident was $8.2 million.

After the leak point was identified, a guided wave was used to ensure integrity of the surrounding pipe. An 18-inch sleeve was welded at the leak location. Two additional sleeves were installed as preventative measures on three additional indications (two indications were covered by one sleeve and the other indication was covered by another sleeve).

Accident 2 – #20190309 - Cushing, OK 2019 (1,200 barrels) – Relief Line

In September 2019, tank farm personnel responded to an unintended movement alarm on a storage tank. Once personnel arrived on location, they discovered crude oil in containment, inside the berm of an adjacent tank. Relief lines were closed to confirm the location of the leak. The failed relief line provided surge relief to a pipeline header that receives oil from a third-party operator.

The metallurgical examination reported that pitting corrosion was caused by MIC. The 12-in relief line pressure was 247 psig at the time of failure and was a dead leg that contained crude oil at low flow. It is likely that this low-flow environment contributed to the MIC that led to the failure. The pipe had been examined in 2019 with a handheld ultrasonic tool and was hydrotested since the original construction to 425 psig.

Considering these findings, the following steps were taken to improve safety of the relief line and reduce the likelihood of future failures:

- Replacement of a substantial portion of the relief line with PTFE internally-coated steel pipe.
- Internal sleeves were used at field joints, and were protected during welding with backing strips, and were bonded to the interior of the line.
- Corrosion monitoring is conducted with a corrosion coupon installed in the relief line.
- Established a line flushing and chemical injection procedure for the relief lines. The purpose of the procedure is to periodically sweep the line of stagnant crude and inject corrosion inhibitor as necessary.
- Installed a check valve immediately downstream from the relief tank to prevent back-flow.

Accident 3 – #20190017 – Houston, TX 2018 (1,000 barrels) – Relief Line

In December 2018, operations personnel noticed a crude oil odor in the terminal. Facility investigations identified product near the 20-in relief line to a storage tank. Operations Control was notified and crude oil pipeline movements into the facility were shut down. The pressure at the point of failure was 20 psig and the line was not flowing at the time. Valves were closed to isolate the relief line and cleanup activities were initiated.

The release originated from a localized pitting feature on the relief line. Relief flow was diverted permanently to an adjacent tank and the section of the failed relief line was abandoned.

Accident 4 – #20180274 - Freeport, TX 2018 (4,922 barrels) – Meter Bank Piping

In August 2018, after about six hours of ship unloading at the marine terminal, a 36-in pipeline failed at 110 psig at the 6 o'clock position due to under deposit internal corrosion. The failed pipeline released 4,922 barrels of crude oil within the containment area of the terminal. Approximately 5 barrels reached the harbor and 4,888 barrels were recovered. There were no fatalities or injuries.


s

Figure 8. Crude Oil Pooling at Leak Location (Photo provided by Enterprise).

Seven minutes following a pressure drop of 32 psig, hydrocarbon vapors triggered a local hazardous gas alarm at the terminal. The controller repositioned the two cameras and identified oil pooling near a meter bank. The local pipeline controller contacted the ship and directed them to shut off the ship's transfer pumps. Two minutes after the first alarm, a second alarm triggered and alerted the controller at the Control Center of an abnormal condition, who initiated remote emergency shutdown by closing the main line block valves of the downstream portion of the system.

While most of the product remained within the containment wall, a crack in the wall allowed a small amount of crude oil to escape, which made its way into the harbor. The section of pipeline that failed was only occasionally operated during ship unloading and, which was considered as a dead leg by the operator. There was no flush plan for the failed section as it was designed in a way in which a flush plan would not flow through it with adequate turbulence to clear BS&W.

The investigation identified the following contributing factors: ineffective implementation of their internal corrosion and integrity management programs (IMP), failure of the leak detection system associated with a large pressure drop of 29%, the failure to implement findings from past accidents to prevent recurrence, and a crack in the containment wall.

Total costs reached more than $4,000,000 including property damage, lost product, emergency response, remediation, repair and costs associated with public and non-operator private property. There were some supply impacts as customers had difficulty moving their product while the terminal was shut down. The supply impacts lasted two weeks until alternate supply methods were developed.

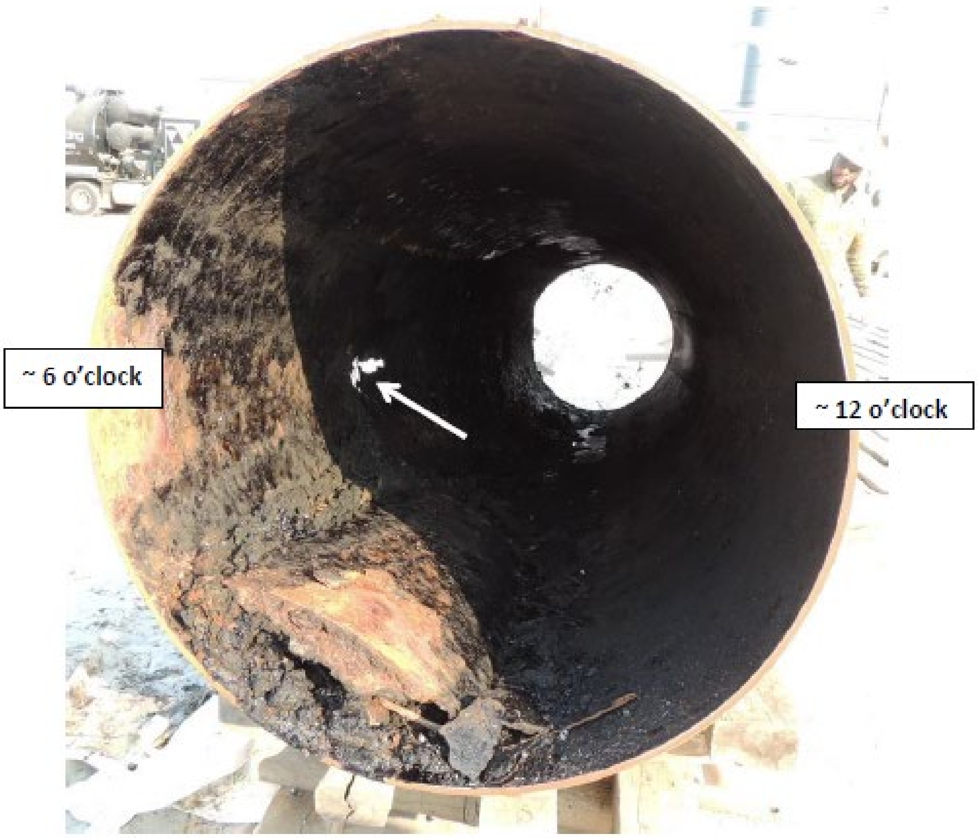


Figure 9. The white arrow indicates the perforation site at 6 o'clock. The sediment at bottom of pipe shifted when the pipe was rotated to place the pipe for field observations (Figure 3 from Stress Engineering Services' Metallurgical Report).

Accident 5 - #20170101 - Falls City, Texas 2017 (1,015 barrels) – Relief Line

In February 2017, local operating personnel noticed crude oil contained within tank dike and determined the source was the tank's 24-inch relief line. The pressure in the line was 5 psig at the time of failure. The final repair was to replace the belowground piping with a new system aboveground that will prevent this dead leg from redeveloping. The operator also established a periodic flushing protocol for these lines to prevent reoccurrence.

Accident 6 – #20150464 – Cushing, OK 2015 (1,000 barrels) - Tank Flush Line

In December 2015, local operating personnel discovered crude oil coming from the ground near a tank flush line at the terminal. At the time of the accident, the pressure within the 16-inch line was less than 10 psig.

Metallurgical analysis concluded that the hole, measuring 1-1/16-inches in diameter and found in the bottom of the 16-inch pipe, was the result of a carbon dioxide-driven attack. Several pits of varying size were found along the bottom of the pipe sample, around which tests registered the presence of hydrogen sulfide, although the report concluded that this did not influence the creation of the pitting. Chemical analysis on deposits within the pit adjacent to the through-wall defect revealed the presence of sand and chlorine, products likely to be entrained in the product stream. Internal corrosion monitoring is conducted primarily through weight loss coupons installed on incoming pipelines at a different terminal. Records show that the average corrosion rate in mils per year (MPY) over the course of three years leading up to the accident was well below what would be considered significant. Additionally, biocide treatment was started in 2012. The tank flush line has been abandoned. Failure Investigation Report[16]

Accident 7 – #20130208 - Cushing, OK 2013 (2,246 barrels) - Tank Fill Line

In May 2013, an operator reported the release of approximately 2,500 barrels of crude oil from a storage tank fill line into on-site containment ponds. The leak, which was not visible at the surface due to vegetation in a drainage swale, and was not identified until an odor was detected by operations personnel, prompting further investigation into line balance calculations and site conditions. Crews constructed dams to ensure the oil remained on the terminal property. The fill line was excavated to investigate the source of the leak, which was found on the bottom of the pipe. This section was idle at the time of the leak's discovery at about 15 psig.

The metallurgical analysis of the 24-in pipe leak reported a hole with dimensions of 1.4-in long by 0.8-in wide that was located beneath black deposits in an area of discrete internal corrosion on the bottom of the pipe. Upon further investigation four corrosion pits found in the pipe. One pit was through wall, while the remaining three pits were between 35% and 53% through wall. There was no evidence of general corrosion or pitting on the external surface of the pipe that could have contributed to the leak.

High to very high concentrations of aerobic, acid-producing, sulfate-reducing, and iron related bacteria were detected on the inside surface of the pipe at the leak site. Additionally, low to moderate concentrations of all five bacteria types were detected in deposits removed from the leak location in an area with no significant corrosion. Based upon the evidence, MIC was the primary source of internal corrosion. The accumulation of deposits/sediments caused by non-flowing conditions contributed to an environment where MIC could occur.

The following contributing factors were identified:

- The operator's existing Operation and Maintenance procedures were incomplete and did not provide technicians with a comprehensive assessment of alarm conditions to identify leaks.
- Many nuisance alarms went off in the control center while the tank movement alarm was received, which may have partially obscured the importance of a specific alarm.
- Technicians do not have dedicated, 24-hour support staff available to help evaluate and manage alarms.

[16] This is a hyperlink to the actual failure investigation report developed by PHMSA staff.

- No documented guidance was provided to operations regarding when inhibition and/or flushing should be used as mitigation strategies.
- Heavy vegetation in site drainage ditches and around ponds may have prevented early detection during routine drive-around site inspections.
- An undetected maintenance issue with an underflow pipe flume (a large corrosion hole in the pipe) allowed oil to migrate out of the upper pond, through a second drainage ditch, and into a lower pond, resulting in increased contamination and the escalation of the event.
- The consequences increased in severity due to misinterpretation of SCADA alarm and tank balance information, thereby delaying the discovery of the real reason for loss of product from the tank. Failure Investigation Report

Accident 8 – #20130130 - Magnolia, AR 2013 (5,600 barrels) - Strainer Vessel for Pump
In March, 2013, the operator arrived at the tank farm and identified a release of crude oil upstream of the pipeline pumps. The pumps receive crude oil from the on-site breakout tanks for delivery into the operator's pipeline, which transports the commodity to a refinery. An estimated 5,600 barrels of crude oil was released, with approximately 1,500 barrels running offsite. The spill occurred in a rural area, affecting the pump station, the pig launcher, the containment pond, and impacted approximately 1.5 miles of a creek.

On the prior evening, the pump was flowing at approximately 2,200 barrels per hour (bph) at 250 psig when it was determined more volume was needed at the refinery. The control center proceeded to shut down the pump and started up a second pump, increasing the flow to 2,500 bph. The switch appeared to be normal with no issues being indicated by their SCADA system. SCADA information was only available for the main line, but not for the station piping. It was determined that the failure occurred during the stop/start sequence of the pump swap, and the buried strainer vessel failed on the suction side of a pump (under tank head pressure for 9-10 hours), releasing crude oil until the next morning.

The strainer was part of the original 1940 construction. The strainer failure was caused by extreme, localized internal corrosion. The internal corrosion was caused by an acidic environment, most probably naphthenic acid (normal in crude oil). There was no evidence of MIC. Failure Investigation Report

Figure 10. Retention pond was designed to capture released oil. Photo from EPA website[17].

Figure 11. The release of oil was caused from a 12-inch underground pipe west of blue suction pump. Photo EPA.

[17] https://response.epa.gov/site/image_list.aspx?site_id=8459&counter=183876

Figure 12. Failed Strainer (external view).

Figure 13. Failed Strainer.

Accident 9 – #20120369 - Mokena, Illinois –2012 (900 barrels) Relief Line

In November 2012, the operator's Control Center received a call from a facility in Illinois indicating the presence of oil on the ground. Several lines were shut down until further investigation could be completed. The leak was confirmed the day after the accident from a relief line near a storage tank. The relief line piping was API 5L Grade X42, 20-in diameter pipe 0.25 in wall thickness, high frequency electric resistance welded seam and fusion bond epoxy coating. The line was installed in 1993.

Further investigation of the source of oil revealed that there was no check valve and the relief line was exposed to head pressure from an adjacent tank. To provide safe delivery operations while the pressure relief system was out of service for repair, a temporary procedure was developed until the relief lines were back in operation.

The failure occurred at a low spot, and metallurgical analysis confirmed that trapped water and MIC contributed to the formation of the pinhole in the bottom of the pipeline. The operator established an elevation study to identify other low spots on the relief line and to determine if internal corrosion could exist in other locations.

Upon digging at one of these other low spots, a defect was discovered during sandblasting in preparation for non-destructive evaluation. Testing also discovered another internal corrosion location near a second storage tank. This second location was abandoned by the installation of a flange and a blind.

Repairs, clean up and restoration was completed by May 2013. Approximately 545,000 ft^3 of contaminated soil was removed from the release site. The total property damage accounted for $9.8 million. Failure Investigation Report

Summary of Attributes in 9 Accident Narratives

Report #	Item that Failed	Age of Pipe	Year Installed	Corrosion Inhibitors	Internal coating	ILI routinely used	Corrosion on Coupons	ILI Tool	Unintentional Release BBLs	Diameter	SCADA In Place	SCADA Detection	Accident Pressure	Wall	PRPTY
20190328	Relief Line	Unknown	Unknown	No	No	No	No	No	1,195	12	Yes	No	12.5	0.375	$ 8,223,045
20190309	Relief Line	8	2011	No	No	No	No	No	1,200	12.75	No	No	247	0.375	$ 1,500,000
20190017	Relief Line	7	2011	Yes	No	No	No	No	1,000	20	Yes	No	20	0.25	$ 158,500
20180274	Meter bank piping to/from ship un/loading	23	1995	No	No	No	No	No	4,922	36	Yes	Yes	110	0.375	$ 4,706,291
20170101	Relief Line	5	2012	Yes	No	No	No	No	1,015	24	Yes	No	5	0.375	$ 233,067
20150464	Tank flush line	22	1993	Yes	No	No	No	No	1,000	16	Yes	No	10	0.25	$ 291,898
20130208	Tank fill line	34	1979	No	No	No	No	No	2,246	24	Yes	Yes	15	0.281	$ 13,844,274
20130130	Strainer vessel upstream of pump	35	1978	Yes	No	No	No	No	5,600	N/A	Yes	No	250		$ 3,384,814
20120369	Relief Line	19	1993	No	No	No	No	No	900	20	No	No	40	0.25	$ 9,800,000

Appendix D - References

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