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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA-2016-0071]

Pipeline Safety: Ineffective Protection, Detection, and Mitigation of Corrosion Resulting from Insulated Coatings on Buried Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this advisory bulletin to remind all owners and operators of hazardous liquid, carbon dioxide, and gas pipelines, as defined in 49 Code of Federal Regulations (CFR) Parts 192 and 195, to consider the overall integrity of the facilities to ensure the safety of the public and operating personnel and to protect the environment. Operators are reminded to review their pipeline operations to ensure that pipeline segments that are both buried and insulated have effective coating and corrosion-control systems to protect against cathodic protection shielding, conduct in-line inspections for all threats, and ensure in-line inspection tool findings are accurate, verified, and conducted for all pipeline threats.

FOR FURTHER INFORMATION CONTACT: Operators of pipelines subject to regulation by PHMSA should contact Mr. Kenneth Lee at 202-366-2694 or e-mail to: kenneth.lee@dot.gov.

SUPPLEMENTARY INFORMATION:

I. Background

On May 19, 2015, the Plains Pipeline, L.P. (Plains), Line 901, a 24-inch pipeline in Santa Barbara County, California, ruptured, resulting in the release of approximately 2,934 barrels of heavy crude oil. The spill resulted in substantial damage to natural habitats and wildlife. This buried pipeline failed due to extensive external corrosion that occurred under the insulated coating.

The Line 901 pipeline is coated with coal tar urethane and covered with foam insulation which, in turn, is covered by a tape wrap over the insulation. Shrink wrap sleeves, which provide a barrier between the steel pipeline and soil for corrosion prevention, are present at the pipeline joints (girth welds) on Line 901. Line 901 carried high-viscosity crude oil at a temperature of approximately 135 degrees Fahrenheit to facilitate transport. Line 901's pipe specifications are API 5L, Grade X-65 pipe, 0.344-inch wall thickness, with a high frequency-electric resistance welded (HF-ERW) long seam. Line 901 was hydrotested to 1,686 pounds per square inch gauge (psig) on November 25, 1990, and has a maximum operating pressure (MOP) of 1,341 psig. Line 901 delivered crude oil into 30-inch Line 903. Line 901 is 10.7 miles in length and Line 903 is 128 miles in length. Line 903 has similar insulated coating and shrink wrap sleeves at girth welds.

Under 49 CFR 195.563, cathodic protection (CP) is required to prevent external corrosion of buried pipelines. Historical CP records for Line 901 revealed protection levels that typically are sufficient to protect non-insulated, buried, coated steel pipe. As mentioned previously, however, Line 901 and Line 903 are insulated. An increasing frequency and extent of corrosion anomalies were noted on both Lines 901 and 903 on in-line inspection tool (ILI) survey results, anomaly excavations, and repairs. PHMSA inspectors noted moisture entrained in the insulation at four excavations performed by Plains on Line 901 after the May 19, 2015 spill.

Plains conducted ILI surveys on Line 901 to assess the integrity of the pipeline in accordance with pipeline safety regulations in 2007, 2012, and 2015. Under § 195.452(j)(3), all pipelines are required to be surveyed at intervals commensurate with the pipeline's risk of integrity threats, but at least every five years. Plains changed Line 901 from a five-year assessment cycle to a three-year assessment cycle after the 2012 ILI survey. Preliminary data from the results of the ILI surveys are summarized below and show a growing number of corrosion anomalies on Line 901. Discrepancies between the ILI data generated during the 2007 and 2012 surveys of Line 901 and the "as found" anomaly sizes discovered in correlation digs after those prior surveys had not been shared with the ILI vendor to reanalyze the data. The frequency and magnitude of the anomalies below are derived from the reported ILI vendor analysis.

24-inch Line 901 - ILI Assessment Results			
Metal Loss	**June 19, 2007**	**July 3, 2012**	**May 6, 2015***
Greater than 80%	0	0	2
60 to 79%	2	5	12
40 to 59%	12	54	80

*Results not received until after spill.

The most recent ILI survey for Line 901 was completed on May 6, 2015. At the time of the spill, the preliminary vendor report had not been received. As a result, no correlation digs for this ILI survey had been attempted.

The May 6, 2015, ILI survey data and subsequent analysis by the ILI vendor predicted external corrosion at the failure site with an area of 5.38 inches by 5.45 inches, and a maximum depth of 47% of the original pipe wall thickness. After the failure, the metallurgical investigators physically measured external corrosion at the failure site to have a maximum depth of 89%. The dimensions of the corrosion feature were 12.1 inches axially by 7.4 inches in circumference. The maximum depth, as measured using laser scan data, was 0.318 inches or 89% of the measured pipe wall thickness (0.359 inches). Discrepancies between the historic ILI data and the "as found" anomaly size had not been shared with the ILI vendor to reanalyze the data.

PHMSA determined that the proximate or direct cause of the release was progressive external corrosion of the insulated, buried steel pipeline. The corrosion occurred under the pipeline's coating system, which consisted of a urethane coal tar coating applied directly to the bare steel pipe, covered by foam thermal insulation with an overlying tape wrap. Water was noted in the foam insulation at a number of digs, indicating that the integrity of the coating system had been compromised. The external corrosion was facilitated by the environment's wet/dry cycling, as determined by the PHMSA-approved, third-party metallurgical laboratory. The release was a single event caused at an area where external corrosion had thinned the pipeline wall thickness. There is no evidence that the pipeline leaked before the rupture. There was a telltale "fish mouth" (a split due to over-pressurization) at the release site indicating the line failed in a single event.

PHMSA's Failure Investigation Report indicated that the proximate or direct cause of the Line 901 failure was external corrosion that thinned the pipe wall to a level where it ruptured suddenly and released heavy crude oil. PHMSA's Failure Investigation Report of the Plains Line 901 incident can be reviewed at:.http://phmsa.dot.gov/staticfiles//PHMSA/DownloadableFiles/Files/PHMSA_Failure_Investigation_Report_Plains_Pipeline_LP_Line_901_Public.pdf. PHMSA's investigation identified numerous contributory causes of the rupture, including:

1) Ineffective protection against external corrosion of the pipeline:
    - The condition of the pipeline's coating and insulation system fostered an environment that led to external corrosion; and
    - The pipeline's CP system was not effective in preventing corrosion from occurring beneath the pipeline's coating/insulation system.
2) Failure to detect and mitigate the corrosion:
    - The ILI and subsequent analysis of ILI data did not characterize the extent and depth of the external corrosion accurately.

Corrosion under insulation (CUI) is recognized as an integrity threat difficult to address through conventional cathodic protection systems and can lead to accelerated wall-loss corrosion and stress corrosion cracking of the pipe steel. A NACE International (NACE) technical committee report titled "Effectiveness of Cathodic Protection on Thermally Insulated Underground Metallic Structures" dated September 2006 (NACE International Publication 10A392, 2006 Edition), was prepared as a guide for external corrosion control of thermally-insulated underground metallic surfaces and considerations of the effectiveness of CP. A summary of the NACE report's conclusions are as follows:

1) "Generally, the application of external CP to thermally insulated metallic surfaces has been ineffective.
2) The principal or primary means of corrosion control of thermally-insulated metallic surfaces is the application of an effective coating on the metallic surface.

3) Care is typically taken in the application of the external jacket and during pipe installation to minimize water ingress, which causes corrosion at imperfections in the primary coating.
4) When practical, the thermally insulated metallic surfaces need to be inspected at routine time intervals for metal loss (e.g., an internal pipeline inspection tool could be used)."

II. Advisory Bulletin (ADB-2016-04)

To: Owners and Operators of Hazardous Liquid, Carbon Dioxide and Gas Pipelines

Subject: Ineffective Protection, Detection, and Mitigation of Corrosion Resulting from Insulated Coatings on Buried Pipelines

Advisory: Operators of hazardous liquid, carbon dioxide and gas pipelines, as defined in 49 CFR Parts 192 and 195, should review their operating, maintenance, and integrity management activities to ensure that their insulated and buried pipelines have effective cathodic protection systems, including coating systems to protect against cathodic protection shielding and moisture under the coatings with higher operating temperatures, and in-line inspection tool findings are accurate, verified, and the in-line tools are appropriate for the pipeline threat. This bulletin is intended to inform operators about PHMSA' failure investigation of the Plains Pipeline May 19, 2015, accident in Santa Barbara, California and to urge operators to take all necessary actions, including, but not limited to, those set forth in this bulletin, to prevent and mitigate the breach of integrity, leaks, and/or failures of their pipeline facilities and to ensure the safety of the public and operating personnel and to protect the environment.

Operators must have and implement procedures to operate, maintain, assess, and repair their pipelines. These procedures for insulated and buried pipelines should take into consideration:

1) The need for coatings and cathodic protection systems to be designed, installed, and maintained so as not to foster an environment of shielding and moisture that can lead to

excessive external corrosion growth rates and pipe steel cracking such as stress corrosion cracking.

2) Coatings for buried, insulated pipelines that may result in cathodic protection "shielding" yet still comply with 49 CFR Part 192, Subpart I or 49 CFR Part 195, Subpart H. Inadequate corrosion prevention may be addressed through any one or more methods, or a combination of methods, including, but not limited to, the following:
    - Replacing insulated and buried pipelines with compromised coating systems or inadequate cathodic protections systems;
    - Repairing or re-coating compromised portions of the coating on insulated and buried pipelines to ensure adequate corrosion control; or
    - Taking other special precautions if an operator suspects that adequate cathodic protection cannot be provided due to shielding resulting from insulated coatings that have become disbonded. Such precautions may include:
        - More frequent reassessments;
        - Usage of the appropriate assessment tools for all threats including stress corrosion cracking;
        - Coordination of data from the appropriate ILI technologies;
        - More stringent repair criteria targeted at CUI or corrosion under disbonded coatings for insulated and buried pipelines;
        - Usage of a leak detection system with instrumentation and associated calculations to monitor line pack (the total volume of liquid present in a pipeline section) along all portions of the pipeline when it is operating or shut down; and
        - Valve spacing to limit any possible spill volumes with remotely operated valves and pressure monitoring at the valves.
3) Advanced ILI data analysis techniques to account for the potential growth of CUI, including interaction criteria for anomaly assessment.
4) ILI data, subsequent analysis of the data, and pipeline excavations that:
    - Confirm the accuracy of the ILI data to characterize the extent and depth of the external corrosion and ILI tolerances and unity charts;

- Follow the ILI guidelines of API Standard 1163, “In-Line Inspection Systems Qualification Standard” 2nd edition, April 2013, (API Std. 1163) for ILI assessments;
- Use additional or more frequent reassessment intervals and confirmations when the insulated and buried pipeline external coating, shields the pipeline from CP, retains moisture on insulated coating systems, and operates at higher operating temperatures; and
- Assess and mitigate operational and environmental conditions in shielded and insulated coatings that lead to excessive corrosion growth rates, pipe steel cracking, and all other threats.

In addition to the above, an operator’s operating and maintenance processes and procedures should be reviewed and updated at least annually, unless operational inspections for integrity warrant shorter review periods.

Issued in Washington, DC on June 15, 2016, under authority delegated in 49 CFR 1.97.

Alan K. Mayberry,

Acting Associate Administrator for Pipeline Safety.

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