Log P-286B

National Transportation Safety Board

Washington, D.C. 20594

Safety Recommendation

Date: March 24, 1987

In reply refer to: P-87-10 and -11

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On April 27, 1985, natural gas under 990 psig ruptured the No. 10 pipeline of the Texas Gas Pipeline Company system. The rupture was in an area weakened by atmospheric corrosion that was located within the pipeline's casing under Kentucky State highway 90 near Beaumont, Kentucky. The ensuing fire killed five persons in a house located north of the rupture, injured three persons as they fled from their house located south of the rupture, and destroyed substantial amounts of property.

On February 21, 1986, natural gas under 987 psig ruptured the No. 15 pipeline of the Texas Eastern Gas Pipeline system. The rupture was in an area weakened by galvanic corrosion and was located south of Kentucky State highway 52 near Lancaster, Kentucky. The force of the escaping gas and the ensuing fire injured three persons as they fled from their houses, resulted in the evacuation of 77 other persons, and destroyed substantial amounts of property. 1/

Over an extended period of time atmospheric corrosion, and possibly electrolytic corrosion to a lesser degree, reduced the wall thickness of the pipeline within the casing under State highway 90 until the pipe could no longer contain the internal pressure whereupon it ruptured suddenly and violently.

Since 1953 the gas company suspected that the pipeline was electrically shorted to the casing at State highway 90 and it had made several unsuccessful attempts in 1954, 1956, and 1964 to eliminate or overcome the effect of the electrical short and to prevent entry of water into the casing. However, the motivation for these actions was to maintain adequate cathodic protection for the pipeline by removing a direct electrical drain on the cathodic protection system. The gas company did not suspect nor did its corrosion monitoring of the pipeline indicate that atmospheric corrosion on the pipe inside the casing was occurring.

1/ For more detailed information, read Pipeline Accident Report--"Texas Eastern Gas Pipeline Company Ruptures and Fires at Beaumont, Kentucky, on April 27, 1985, and Lancaster, Kentucky, on February 21, 1986" (NTSB/PAR-87/1).

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The gas company did not believe the electrically shorted casing to be a problem affecting the integrity of the pipeline. It had operated its pipeline system for many years during which time more than 150 casings had been found to be electrically shorted to the pipeline and it had never experienced leaks or ruptures at these locations. The experience of other operators of pipelines and of the Office of Pipeline Safety (OPS) indicate that the gas company's assessment about the dangers posed by its electrically shorted casing was not unreasonable. For example, the OPS's guidance to its investigators advise that where it is not practical to eliminate the electrical short, the operator may chose to monitor for gas leakage within the casing and if such leakage were detected, immediate corrective action then would be required; the gas company did not do this. Had the gas company believed that the electrically shorted casing posed a threat either to public safety or to its pipeline, it would have been prudent to have corrected this problem at the time it modified its pipeline crossings of State highway 90. However, the gas company did not do this because it did not consider the electrical short to be a problem to the pipeline and it had no evidence to suggest that its pipeline was being damaged by atmospheric corrosion.

The only practical methods available to the gas company for detecting the atmospheric corrosion damage to the pipeline within the casing were periodic hydrostatic testing of the pipeline to confirm its integrity and the use of in-line inspection equipment. It was already performing in-line inspections of its pipelines in areas where its annual corrosion test station monitoring or close interval surveys indicated unusual or abnormal conditions. The pipeline crossing under State highway 90 had not been subjected to an in-line inspection because its corrosion monitoring indicated that the protection level of the line coming into and going out of the casing was in excess of that required by Federal regulations. The gas company did not believe that the identical pipe-to-soil (p/s) and casing-to-soil (c/s) readings at State highway 90 constituted a corrosion problem.

For an extended period of time, the pipeline segment which lay south of State highway 52 near Lancaster had not received an adequate level of protection against corrosion. This segment was shielded from the cathodic protection system by a rock formation below the pipeline and this allowed galvanic corrosion to reduce the wall thickness of the pipe until it could no longer contain the internal pressure whereupon the pipe ruptured suddenly and violently.

The gas company's annual corrosion monitoring at test stations and its previous close interval survey provided no indication that corrosion of the pipe was occurring. In fact, the corrosion monitoring actually showed higher negative voltages than the required negative 0.85 volt, which indicated to the gas company that the pipe was well protected against corrosion. The corroded segment was identified on September 12, 1985, 5 months before the accident, through the gas company's use of an in-line inspection instrument; however, no corrective action was taken at that time.

The gas company personnel who excavated the corroded area to document the extent of the corrosion did so primarily to confirm that the in-line instrument was functioning properly during the inspection run and to gather data to assist other gas company personnel in the interpretation of the permanent graph. The gas company personnel were expected to identify any seriously corroded segments of pipe and to alert the gas company when they believed remedial measures should be taken. However, the pipe was not further excavated so that the full extent of the corrosion damage could be documented and thus, its potential for failure could not be assessed. As a result, these employees determined, based on insufficient data, that no immediate corrective action was required.

Information developed during the investigations of these accidents and the reviews of regulations and recommended practices for monitoring the effectiveness of corrosion control methods makes it clear that improvements in this area are necessary. The accident at Beaumont indicates that pipelines installed in vented casings are subject to damage by atmospheric corrosion; however, this potential hazard is not addressed in the Federal regulations, in the National Association of Corrosion Engineers (NACE) corrosion control practices, or in the ASME guidance to operators of pipelines. No guidance is provided by the OPS, ASME, or NACE by which data obtained from p/s and c/s measurements depicting an electrical short circuit can be used to estimate the amount of corrosion damage which has already occurred on the encased pipe. In fact, no guidance is provided to show that corrosion of any kind is occurring in these situations. The information obtained during the investigation about the affects on safety of pipelines being electrically shorted to a casing indicates that this condition has not caused a significant number of pipeline ruptures; however, damage from this condition, as with atmospheric corrosion, is dependent upon many factors of which the most important may be the duration of exposure. Periodic inspection is needed to determine the damage corrosion already has caused to pipelines installed within casings or to determine when corrosion on pipelines has progressed to the extent the pipe should be replaced.

Information gathered as a result of the accident at Lancaster indicates that the corrosion monitoring method specifically required by the Federal regulations—annual readings taken at corrosion test stations—often is insufficient for identifying areas of corrosion on pipelines. This accident and information obtained during the investigation, demonstrated that pipeline segments installed on or over large rock formations or installed over or adjacent to other large buried structures can be shielded from the protection of corrosion mitigation systems. More important, however, is the fact that segments of pipelines unprotected because of shielding are difficult if not impossible to detect using conventional corrosion monitoring methods. It was only through the gas company's use of the in-line inspection instrument that the hundreds of corrosion damaged segments finally were detected, providing an opportunity for the gas company to take remedial action.

Moreover, neither the Federal regulations, the NACE recommended practice, or the ASME guidelines provide specific criteria or other guidance to assist gas pipeline operators in determining when the annual test station monitoring may not be effective for identifying areas of corrosion. They do not advise about the use of close interval surveys, hydrostatic testing, or in-line instrument inspection and their usefulness in identifying areas of corrosion. They do not require or recommend that operators of pipelines, when modifying existing pipelines or constructing new pipelines, make provision for the use of in-line inspection instruments.

As a result of its investigation, the National Transportation Safety Board issued the following recommendations to the National Association of Corrosion Engineers:

> Revise Recommended Practice RP-01-69 to incorporate specific guidance on the conditions under which each of the cathodic protection criterion should be used, on the conditions under which the internal resistance drop should be considered in pipe-to-soil voltage potential measurements, on the conditions which may shield buried pipe from the benefits of cathodic protection systems, on the effective use of available methods for identifying areas of active cathodic and atmospheric corrosion, and on effective methods for identifying previous corrosion damage to buried pipelines. (Class III, Longer Term Action) (P-87-10)

> Develop a system for collecting information on corrosion-caused pipeline failures and leaks to evaluate the adequacy of criteria and procedures included in its recommended practices for controlling the corrosion of buried pipelines. (Class III, Longer Term Action) (P-87-11)

Also, as as result of its investigation, the Safety Board issued Safety Recommendation P-87-1 to the Texas Eastern Gas Pipeline Company, P-87-2 through -9 to the Research and Special Programs Administration of the U.S. Department of Transportation, and P-87-12 to the American Society of Mechanical Engineers Gas Piping Standards Committee.

The National Transportation Safety Board is an independent Federal agency with the statutory responsibility ". . . to promote transportation safety by conducting independent accident investigations and by formulating safety improvement recommendations" (Public Law 93-633). The Safety Board is vitally interested in any actions taken as a result of its safety recommendations and would appreciate a response from you regarding action taken or contemplated with respect to the recommendations in this letter. Please refer to Safety Recommendations P-87-10 and -11 in your reply.

BURNETT, Chairman, GOLDMAN, Vice Chairman, LAUBER and NALL, Members, concurred in these recommendations.

By: Jim Burnett
Chairman