Log P-386A

National Transportation Safety Board

Washington, D.C. 20594

Safety Recommendation

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In reply refer to: P-87-2 through -9

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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/

The gas company's program for training its compressor station personnel and for reviewing these employees' knowledge about actions to take during emergencies apparently was adequate in that these employees did take prompt, effective action in responding to both the Beaumont and Lancaster accidents. Additionally, during the Beaumont accident the implementation of its procedures for coordinating with response personnel during the emergency was effective.

There were, however, deficiencies which were identified in other procedures and employee activities. The gas company emergency procedures were not followed explicitly during the emergency at Lancaster apparently because the compressor station supervisor did not understand why emergency response personnel needed the requested information and because he was concerned that the information provided would be made available to the news media. He knew that according to the gas company procedures, providing information to the news media was reserved for higher level company representatives.

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).

This failure to provide the requested information to emergency response personnel did not in this instance cause or contribute to any greater loss; however, it did greatly hamper the civil agencies in carrying out their duties to assure the safety of their own personnel and it did nothing to ease the concern of the evacuated citizens about the safety of their homes and possessions and their inconvenience in having to find temporary shelter. It does demonstrate that the gas company should improve its training and testing of supervisory personnel to be certain that they know what types of information should be provided to emergency response agencies and that they understand why full cooperation should be extended to these agencies.

Additionally, the gas company did not train its corrosion technicians in making critical assessments about the affect of corrosion damage on its pipelines rather, the gas company relied heavily upon the undefined and differing experiences of its corrosion technicians for making judgments about the effect of corrosion-damaged areas on the continued safety of its pipelines. As demonstrated by the actions taken by these technicians before the accident at Lancaster, the experience of these gas company personnel was not adequate to access the danger posed by the corrosion of the excavated pipe. While this specific deficiency may have been corrected by implementing new procedures and training for its corrosion technicians, this and the previously discussed training deficiency indicates that improvement is needed in the area of employee qualifications and training. To assist the gas company in making necessary improvements, it should develop proper selection and qualification criteria to implement effective training and testing programs on normal and emergency operations.

The need for improvements in a gas company's employee selection, training, and testing programs has been addressed frequently in Safety Board reports of pipeline accidents. The reason deficiencies in employee qualification and training continue to be identified during the investigations of accidents is because the Office of Pipeline Safety (OPS) has not yet fully developed and incorporated comprehensive requirements for the qualification and training of pipeline operator employees who perform the various functions required by the regulations. The most complete requirement about training included in the regulations applies to the gas company's emergency plans. Section 49 Code of Federal Regulations Part 192.615 requires the gas company to train appropriate operating personnel on the procedures to be used during emergencies, to verify in some manner that the training was effective, and to review employee activities after an emergency to determine if the procedures were effectively followed.

Proper planning for emergencies, training of employees responsible for carrying out actions during emergencies, and a review of activities after the emergency all are important tasks. However, preventing emergencies from occurring through proper operation and maintenance of pipeline systems is equally important. Therefore, the OPS should require for all activities addressed by the regulations that employee qualifications be developed through job/task analyses, that employees be trained in the proper performance of assigned tasks, and that employees be periodically tested to demonstrate that they understand and are able to perform their assigned responsibilities.

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.

Other factors also were involved in the failure of gas company personnel to recognize the threat posed to public safety, to themselves, and to the pipeline. The gas company, without knowing or taking action to determine the ability of its corrosion technicians for assessing the affect of corrosion damage on its pipelines, depended upon the varying experience of each of its employees to support them in making critical decisions relative to the safety of the pipeline. No specific training or analytical guidance on methods for assessing the affect of corrosion damage was provided to its personnel by the gas company to support them in performing this responsibility.

Also, neither the gas company procedures at that time nor the Federal regulations specifically required continued excavation and inspection of areas of corrosion damage until corrosion was no longer evident. Had this been required and had the pipe been fully examined for evidence of corrosion damage, the corrosion technicians then would have obtained sufficient information about the extent of corrosion damage to have indicated that immediate action was necessary to prevent the rupture of the pipeline at State highway 52.

Additionally, because of the earlier pipeline rupture at Beaumont, Kentucky, the gas company had embarked upon a greater than normal in-line inspection program which imposed increased workloads on key personnel charged with corrosion control and monitoring responsibilities. The incomplete preparation of the field inspection report on this corrosion damage, the failure to fully document and properly assess the extent of corrosion damage during the field examination, and the less than adequate attention given by the Corrosion and Pipeline Departments located in Houston, Texas, to this report of corrosion damage probably were adversely influenced by the large influx of information on the condition of the pipeline. These factors resulted in the gas company not taking action to prevent the rupture of a segment of pipeline even though the information on the corrosion damage obtained 5 months previous was sufficient to have raised serious concern about the consequences of continuing operations without taking remedial action to either reduce the pressure or replace the damaged section of pipeline at State highway 52.

To overcome deficiencies identified after this accident, the gas company developed procedures requiring exposed pipelines to be excavated until no corrosion effects are evident, to document fully the extent of corrosion damage to its pipelines, and to assess the effect of this damage on the continued operation of its pipelines by performing the calculations recommended by the American Society of Mechanical Engineers (ASME). The gas company has equipped its corrosion technicians with preprogrammed calculators and has trained and tested the technicians in the application of these procedures.

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 provisions for the use of in-line inspection instruments.

OPS has developed the most comprehensive guidance concerning the actions a pipeline operator should take for identifying corrosion damage and other deficiencies on its pipeline and for responding to the identified deficiencies. However, this guidance has been developed for and provided to its personnel for their use in uniformly carrying out regulatory compliance inspections. The OPS guidelines better define the intent of specific regulations and provide information on the types of actions which may be taken to comply with the requirements. The Safety Board believes that these guidelines also would benefit the regulated pipeline industry much in the same manner it assists OPS's personnel in administering these primarily performance-type regulations. Moreover, it seems reasonable that by having access to these OPS guidelines, the pipeline industry would be better able to conform with the OPS interpretation of the regulations.

When the ruptures occurred at Beaumont and Lancaster, the operating pressure of both pipelines was above that allowed for pipelines newly constructed using improved steels, improved electrical insulation materials, and many additional improved procedures and materials. This higher operating pressure has been allowed for many pipeline companies without limitation through a "grandfather" provision incorporated in the Federal pipeline standards when they were promulgated in 1970. Had the pressure been limited to 936 psig (72 percent of the specified minimum yield strength), the allowable pressure if it had been a newly constructed similar pipeline, the accident at Beaumont would still have occurred, although probably at a later date, because it is unlikely that the ongoing atmospheric corrosion would have been detected. However, at Lancaster, the accident probably would not have occurred until a later date had the maximum allowable operating pressure for the pipeline been limited to 72 percent of the SMYS. This limitation would have resulted in an operating pressure of 924 psig at the area where the pipe was found to be damaged by corrosion rather than the 965 psig pressure at the time of the failure. This difference in pressure may well have allowed the gas company to have replaced the damaged segment before the accident.

The net effect of a lower maximum allowable operating pressure on the corroded areas of these pipelines would depend on many variables. However, the Safety Board does not believe it is sound engineering practice to allow older pipelines, constructed with materials and procedures inferior to those used in new pipelines, to operate at SMYS levels greater than those new pipelines. At the time the Federal requirements were promulgated, it may not have been practical to have required all existing pipelines to immediately conform to the new maximum pressure standard (72 percent of SMYS). Thus it would have been reasonable to have provided a "grandfather" provision to allow continued operation of existing pipeline at the higher pressures. However, the regulations should have established a time by which all existing pipelines would be required to adhere to the new standard. The OPS should take action expeditiously to correct this longstanding deficiency.

As a result of its investigation, the National Transportation Safety Board issued the following recommendations to the Research and Special Program Administration, U.S. Department of Transportation:

> Amend 49 CFR Parts 192 and 195 to require that operators of pipelines develop and conduct selection, training, and testing programs to annually qualify employees for correctly carrying out each assigned responsibility which is necessary for complying with 49 CFR Parts 192 or 195 as appropriate. (Class III, Longer Term Action) (P-87-2)
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> Amend 49 CFR 192.459, External corrosion control, Examination of buried pipeline when exposed, to require pipeline operators to fully expose and fully examine pipelines exposed for any reason. The exposure and examination should continue until corroded or other damaged areas are no longer encountered. (Class III, Longer Term Action) (P-87-3)

Require operators of both gas and liquid transmission pipelines to periodically determine the adequacy of their pipelines to operate at established maximum allowable pressures by performing inspections or tests capable of identifying corrosion-caused and other time-dependent damages that may be detrimental to the continued safe operation of these pipelines and require necessary remedial action. (Class III, Longer Term Action) (P-87-4)

Establish criteria for use by operators of pipelines in determining the frequency for performing inspections and tests conducted to determine the appropriateness of established maximum allowable operating pressures. (Class III, Longer Term Action) (P-87-5)

Require existing natural gas transmission and liquid petroleum pipeline operators when repairing or modifying their systems, to install facilities to incorporate the use of in-line inspection equipment. (Class III, Longer Term Action) (P-87-6)

Require that all new gas and liquid transmission pipelines be constructed to facilitate the use of in-line instrument inspection equipment. (Class III, Longer Term Action) (P-87-7)

Make available to the regulated gas and liquid pipeline industries the guidance information Office of Pipeline Safety provides to its inspectors for determining compliance with the pipeline safety regulations. (Class II, Priority Action) (P-87-8)

Revise 49 CFR 192 and, if necessary, request legislative authority to amend 49 CFR 192 to eliminate the "grandfather clause" which permits operators of pipelines installed before November 12, 1970, to operate at levels of stress that exceed those levels permitted for pipeline installed after the effective date of 49 CFR 192. (Class II, Longer-Term Action) (P-87-9)

Also, as as result of its investigation, the Safety Board issued Safety Recommendations P-87-1 to the Texas Eastern Gas Pipeline Company, P-87-10 and -11 to the National Association of Corrosion Engineers, and P-87-12 to the American Society of Mechanical Engineers Gas Piping Standards Committee.

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

Jim Burnett

By: Jim Burnett
Chairman