



National Transportation Safety Board
Washington, D.C. 20594

Addendum (Reconsideration Request) to:

Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire,
Edison, New Jersey March 23, 1994

PAR-95-01, adopted on 1/18/1995
PB95-916501



National Transportation Safety Board
Washington, D.C. 20594

MAY 18 2001

Mr. Steven R. Weinmann, Petitioner
Representing: Quality Materials, Inc.

Pipeline Accident
Edison, New Jersey
March 23, 1994
NTSB Report: PAR-95/0 1

RESPONSE TO PETITION FOR RECONSIDERATION

In accordance with the National Transportation Safety Board's rules (49 *Code of Federal Regulations* Part 845), the Safety Board has reviewed the petition for reconsideration and modification of one of the conclusions in the Safety Board's pipeline accident report regarding the pipeline accident that occurred on March 23, 1994, in Edison, New Jersey. Petitioner asked that the Safety Board "reconsider or modify its conclusion that the damage causing the rupture was not present in 1986." Based on its review of the petition, filed on September 14, 1995, the Safety Board hereby grants the petition in full.

A 36-inch-diameter natural gas pipeline, Line 20, owned and operated by Texas Eastern Transmission Corporation (TETCO), failed catastrophically on March 23, 1994. The ruptured portion of the buried pipeline was on the property of Quality Materials, Inc., (Quality). Escaping gas from the pipeline was ignited within minutes after the rupture, sending flames several hundred feet into the air. Radiant heat from the burning gas ignited a fire at the Durham Woods Apartment Complex, located more than 100 yards from the rupture site. The fire destroyed several buildings on the west side of this apartment complex. Estimated damage from the accident exceeded \$25 million. No fatalities resulted from the accident.

Parties to the investigation were the Middlesex County Police Department, TETCO, the Office of Pipeline Safety (OPS) of the Research and Special Programs Administration, the New Jersey Bureau of Pipeline Safety, and Edison Township.

As a result of its investigation, the Safety Board determined that the probable cause of the pipeline rupture was mechanical damage to the exterior surface of the pipe that reduced the pipe wall thickness and likely created a crack in the gouge that grew, most likely through metal fatigue, to critical size. Petitioner is not disputing the probable cause of the accident.

One of the Safety Board's findings was that TETCO's Line 20 was gouged by excavation equipment, such as a backhoe, at an undetermined time after the pipeline was internally inspected in 1986. Petitioner has requested that the Safety Board modify or reconsider this conclusion.

In support of his petition, petitioner submitted an August 31, 1995, report and a September 11, 1995, affidavit, both prepared by Mr. H. Noel Duckworth, petitioner's consultant. In his affidavit and report, Mr. Duckworth contends that the dent containing the gouge that was determined to be the point of origin of the rupture was, in fact, reflected on the 1986 internal inspection survey logs. Mr. Duckworth identified a four-channel signal on the copies of the 1986 survey logs that he presented to Safety Board staff. This four-channel signal is approximately 62 inches upstream from the girth weld (reference point), at a position of about 1:45 o'clock circumferential (# 21, Exhibit I-2). Mr. Duckworth contends that this four-channel signal reflects defect 21, the point of origin of failure.

A meeting between the parties to the investigation and the petitioner was conducted by the Safety Board on October 30, 1996, at Safety Board headquarters, 490 L'Enfant Plaza, Washington, D.C. The Middlesex County Police Department, TETCO, and the OPS sent representatives to the meeting. TETCO also provided written comments, while the OPS and the New Jersey Bureau of Pipeline Safety each provided a no-comment document. The remaining party to the investigation, Edison Township, did not send representatives to the meeting or provide a written document.

Other information received by the Safety Board in response to the petition included a document prepared by Haskell Excavating Company (predecessor to Quality), reports from two consultants hired by the State of New Jersey Division of Criminal Justice, and an affidavit from Mr. Pat Daigle of Tuboscope (the company that had performed the 1986 internal inspection of the failed pipeline). With the exception of the two reports prepared by the consultants for the State of New Jersey, all the documents received were shared with all the parties.

TETCO stated that Quality did not present any new evidence and that analysis presented on Quality's behalf was flawed and distorted. Mr. Dwayne Kisilevich, an independent TETCO consultant, in documents submitted to the Board and during the investigative meeting, acknowledged a small indication on the survey logs of a possible dent near the point of origin of failure. However, Mr. Kisilevich identified other such survey log indications in the vicinity of the failure origin for which no visible damage was present on the pipe. Mr. Kisilevich attributed these false indications to the metal debris likely buried in proximity to the pipeline. Mr. Kisilevich identified four gouges associated with dents that were similar to the point of origin of failure. He stated that these four damage areas were reflected on the 1986 internal inspection survey logs but that the gouge at the failure origin was not. He therefore concluded that the gouge believed to be the point of origin of failure occurred after the 1986 internal inspection. Mr. Kisilevich also identified five 70- to 120-mils-deep defects (damage areas) on the pipeline within the 10-foot section containing the fracture origin area that should have shown corresponding indications on the survey logs. These indications were not, however, visible to him on the survey logs, leading him to conclude that these defects were produced after the 1986 internal inspection.

Mr. Duckworth stated that the defects that were not visible on the survey logs to which Mr. Kisilevich referred were longitudinal and that this would explain why they probably were not detected by the equipment.

In his February 2, 1996, affidavit, Mr. Pat Daigle of Tuboscope stated that an indication was present on the survey log at the point of origin of failure (approximately 59 inches from the downstream weld). But he stated that the signals presented on the log would not have been considered significant because of their small size and the characteristics of the indication.

In response to questions from the Safety Board to TETCO regarding this investigation, Ms. Pam Moreno of Tuboscope, in a February 17, 1997, letter, stated that indication # 21 in the internal inspection survey log submitted by Mr. Duckworth (Exhibit I-2) appears to be the same as indication B in the internal inspection survey log submitted by TETCO (Exhibit D). In Exhibit I-2, indication # 21 appears on four channels, and in Exhibit D, indication B appears only on one channel. However, the horizontal scale of Exhibit D is approximately six times that of Exhibit I-2. The petitioner contends that the four-channel signal in Exhibit I-2 reflects defect 21, the point of origin of failure.

The two consultants hired by the State of New Jersey noted that a signal is present in the survey log at a location that appears to correspond to that of the dent containing the gouge that is believed to have been the point of origin of failure. They disagreed only about whether the signal represents a gouge or a dent.

After reviewing all the available information, including the pertinent information summarized above, the Safety Board acknowledges the possibility that the dent containing the rupture origin was present on the pipeline when the 1986 internal inspection of Line 20 was performed. Often, a gouge within a dent will occur at the time the dent is created; however, the limitations of the inspection tool and complexities involved in interpreting the survey log data make it impossible to determine conclusively whether the gouge believed to be the point of origin of the failure was present at the time of the 1986 internal inspection.

Based on the above, the petition for reconsideration filed September 14, 1995, requesting reconsideration or modification of an identified conclusion in NTSB Pipeline Accident Report: PAR-95/01 is granted. Accordingly, changes have been made to the Factual (page 21), Analysis (page 40), and Conclusions (page 74) sections of the report. These changes are reflected on the attached revised pages.

Acting Chairman CARMODY and Members HAMMERSCHMIDT, BLACK, and GOGLIA concurred in this response to petition for reconsideration.

Attachments

Proposed Revisions to Pages 21, 40, and 74 of
Pipeline Accident Report- *Texas Eastern Transmission
Corporation Natural Gas Explosion and Fire
Edison, New Jersey. March 23, 1994.*

Response to Petition for Reconsideration

After the accident, the TETCO South Plainfield Area Superintendent reviewed the log and identified seven indications for the pipe through the asphalt plant property. All indications were graded as minor anomalies, six as 1- and one as 1. He and an inspection tool contractor representative reexamined the log closely to determine whether indications of anomalies were near the rupture origin and found none. The Safety Board's review of the log identified no metal-loss anomalies in the area of the fracture origin or in the numerous large gouges on the pipe. Safety Board investigators noted two log indications on the pipe segment that included the origin gouge and one indication on the next pipe segment which they believed warranted additional investigation. On the origin gouge pipe segment, the two indications were 9.5 feet and 18 feet west of the east girth weld. The Board determined that the indication nearer the east girth weld represented an area of metal loss about 1 inch square and about 0.050 inch deep. The other indication represented a slightly smaller square area about 0.050 inch deep. The indication on the pipe segment east of the origin segment represented an isolated pit about 0.100 inch deep.

The area superintendent stated that after examining the various gouges in the origin pipe segment, he believes that had they been present at the time of the 1986 internal inspection, the smart pig would have detected and charted them. TETCO would then have identified the indications on the log as Grade 2 and excavated to inspect the pipe. He said the absence of any indications logged near the rupture origin convinces him the gouges were not present when Line 20 was pigged in 1986. The TETCO official's observations are supported by the Log Interpretation Department Supervisor of Tuboscope Pipeline Services, the manufacturer and operator of the pig used in the 1986 inspection. In a November 1, 1994, letter, the supervisor states that after comparing the marks and their locations on the pieces of pipe at the rupture site with the metal loss indications on the 1986 inspection log, she determined that some "small gouges" downstream of the rupture "correlated to the indications seen on the 1986 survey." She further states that gouges such as those found at the origin "would be expected to have significant signatures on the 1986 survey..." and that "no such signatures are visible."

A consultant retained by Quality submitted to the Safety Board a report and an affidavit in which he contended that the 1986 internal inspection logs did show a dent at or near the rupture site. An independent TETCO consultant acknowledged an indication in the logs of a possible dent near the origin of failure, but he identified this as a false indication resulting from metal debris likely buried in proximity to the pipeline. A Tuboscope representative also submitted an affidavit stating that an indication was present in the logs, but that the signals would not have been considered significant because of their small size and their characteristics. Two consultants hired by the State of New Jersey noted the presence in the logs of a signal at a location that appeared to correspond to the origin of the rupture; however, the two consultants could not agree on whether the signal represented a dent or a gouge.

TETCO officials said that Line 20 was scheduled and budgeted to be pigged in 1994 because of the line's class location, its criticality to service, and the many grade 1 indications detected in the 1986 internal inspection; however, the company did not have the opportunity to internally inspect the 1 line before the March rupture.

ANALYSIS

Metallurgical analysis of the Line 20 pipe fragments after the accident show the scrapes were made by nonexcavation activities and the gouges were made by mechanized excavation equipment. The Safety Board was able to determine that the nonexcavation scrapes were made in 1984 when plant personnel tilled the sediment pond with dirt and plant debris. ~~The Board was able to determine that the gouges were made after June 1, 1986, but the Board was unable to determine when the gouge at the fracture origin~~ wasthey were made or who made itcaused them. In the following analysis, the Board lists the factors and conditions it was able to exclude, identifies improvements needed for pipelines, especially in urban areas, and discusses the need for improved pipe metal properties to limit pipeline failures and/or mitigate their consequences.

Exclusions

The findings from TETCO's 1986 magnetic flux internal inspection ~~which the company verified by excavating, inspecting, and tilling the sediment pond at the pipeline,~~ indicate the rupture origin gouge and other major gouges ~~found on the pipe at the time of the accident were not present when the line was pigged in 1980.~~ The indications on the 1986 internal inspection log were of did not indicate metal losses & sufficient to have caused pipe failure. Witnesses recall and aerial photo-graphs show heavy equipment, including a bulldozer and dredging equipment, being operated in the area of the sediment pond over the pipeline before TETCO's 1986 internal inspection of Line 20. The metal loss indications on the 1986 log corresponds with minor scrape marks on the pipe within the pond. The Safety Board concludes that the indications detected in the 1986 internal inspection were the deeper portions of scrapes made when plant employees bulldozed plant debris and dirt into the sediment pond and when dredging equipment contacted the pipe during sediment removal operations. The Board further concludes that the gouge that ultimately resulted in pipe failure was caused by excavation activity ~~some time after June 1, 1986~~ performed at some undetermined time.

The gouges on the pipe were not the result of recent excavation damage. The Safety Board examined the microstructure of the pipe material underlying the non-rupture origin crack and found it was heavily deformed and contained a crack covered with corrosion deposits. The large build-up of corrosion deposits in the non-origin crack indicates that the crack was present in the pipe metal for some time, likely from when the pipe was gouged.

The gouge damage alone was not sufficient to cause the steel pipe to fail under operating pressure when it was injured. Also, subsequent operation of the damaged pipe even at maximum pressure did not cause the rupture. During the 2 years before the rupture, TETCO frequently operated Line 20 at maximum pressure without failure.

Pipeline employee performance was not a factor in the pipe being damaged or in the damage not being detected by TETCO. From interviews and observations, the Safety Board determined that the survey pilot can easily observe activities and vegetation along the pipeline route without experiencing any workload problems. From interviews with the

CONCLUSIONS

Findings

1. On the day of the accident, Line 20 did not fail as a result of human error, or as a result of excessive operating pressure, ~~or from excavation damage caused before 1986~~
2. TETCO's Line 20 was gouged by excavation equipment, such as a backhoe, at ~~an~~ some undetermined time ~~after the pipeline was internally inspected in 1986.~~
3. The mechanically-induced gouge at the rupture initiation likely created a crack in the gouge that grew to a critical size, most likely as a result of metal fatigue.
4. Exempting pipelines in any class location from Federal marking requirements increases the potential for excavation damages. Clearly marking the route of Line 20 through the asphalt plant property may have increased the likelihood that the employees of Quality Materials, Inc. notified TETCO prior to excavating.
5. Periodic instrumented inspection of pipelines can identify most types of injurious defects and damages before a rupture occurs.
6. A pipe metal having good toughness properties may have sustained the gouges without failure or sustained a substantially smaller failure opening that would have reduced the rate at which gas was released. The brittle failure of Line 20 allowed the release of the natural gas at the maximum possible rate.
7. Although many TETCO requirements and procedures surpassed those required by Federal regulations, the company's surveillance procedures did not stress that employees identify excavation activities within industrial locations that could endanger its pipeline.
8. Quality Materials, Inc., did not advise its employees about the presence of or potential hazards posed by the pipeline within the plant property, or implement precautionary measures to protect Line 20 from excavation damage by employees.
9. TETCO's lack of automatic- or remote-operated valves on Line 20 prevented the company from promptly stopping the flow of gas to the failed pipeline segment, which exacerbated damage to nearby property.
10. RSPA's study on reducing public safety risks with respect to pipeline siting, if modified to assess the effect of building standards for structures near pipelines, offers significant potential for identifying necessary additional actions.
11. The public will not benefit from the safety improvement recommendations developed in RSPA's public safety risk study without guidance containing implementation procedures and without motivation from associations representing local governments.

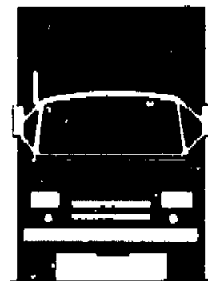
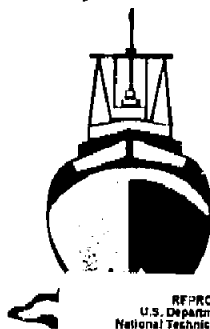
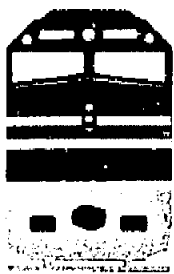
PB95-916501
NTSB/PAR-95/01

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C. 20594

PIPELINE ACCIDENT REPORT

TEXAS EASTERN TRANSMISSION CORPORATION
NATURAL GAS PIPELINE EXPLOSION AND FIRE
EDISON, NEW JERSEY
MARCH 23, 1994



6362A

REPRODUCED BY:
U.S. Department of Commerce
National Technical Information Service
Springfield, Virginia 22161

Abstract: This reports explains the rupture of a Texas Eastern Transmission Corporation natural gas pipeline, subsequent release of product, and resultant ignition and fire in Edison Township, New Jersey, on March 23, 1994. From its investigation of this accident, the Safety Board identified safety issues in the following areas: public safety near pipelines and steel pipe toughness properties. The National Transportation Safety Board made safety recommendations addressing these issues to the Research and Special Programs Administration, the Texas Eastern Transmission Corporation, the American Public Works Association, the Interstate Natural Gas Association of America, the Association of Oil Pipe Lines, the American Petroleum Institute, the American Gas Association, the American Society of Civil Engineers, the International City/County Management Association, and the American Planning Association.

The National Transportation Safety Board is an independent Federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable cause of accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The Safety Board makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

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**NATIONAL TRANSPORTATION
SAFETY BOARD**

Washington, D.C. 20594

PIPELINE ACCIDENT REPORT

**TEXAS EASTERN TRANSMISSION CORPORATION
NATURAL GAS PIPELINE EXPLOSION AND FIRE
EDISON, NEW JERSEY
MARCH 23, 1994**

Adopted: January 18, 1995

Notation 6362A

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EXECUTIVE SUMMARY

About 11:55 p.m. on March 23, 1994, a 36-inch diameter pipeline owned and operated by Texas Eastern Transmission Corporation ruptured catastrophically in Edison Township, New Jersey, within the property of Quality Materials, Inc., an asphalt plant. The force of the rupture and of natural gas escaping at a pressure of about 970 psig (pounds-per-square-inch gauge) excavated the soil around the pipe and blew gas hundreds of feet into the air, propelling pipe fragments, rocks, and debris more than 800 feet. Within 1 to 2 minutes of the rupture, one of several possible sources ignited the escaping gas, sending flames upward 400 to 500 feet in the air. Heat radiating from the massive fire ignited several building roofs in a nearby apartment complex. Occupants, alerted to the emergency by noises from escaping gas and rocks hitting the roofs, fled from the burning buildings. The fire destroyed eight buildings. Approximately 1,500 apartment residents were evacuated.

Most injuries were minor foot burns and cuts that apartment residents sustained from the hot pavement and glass shards as they fled the complex. Response personnel evacuated 23 people to a local hospital and another estimated 70 apartment residents made their own way to hospitals, where they were treated and released. No resident of the complex suffered a fatal injury as a result of this accident. However, a woman who lived about 1 mile from the accident site and who had a history of heart trouble suffered a heart attack and died shortly after the rupture and fire. Damage from the accident exceeded \$25 million.

The National Transportation Safety Board determines that the probable cause of the rupture of Texas Eastern Transmission Corporation's Line 20 in Edison Township, New Jersey, was mechanical damage to the exterior surface of the pipe that reduced the wall thickness and likely created a crack in the gouge that grew, most likely through metal fatigue, to critical size. Contributing to the rupture were the brittle properties of the pipe material at the operating temperature. Contributing to the severity of the accident was the inability of Texas Eastern Transmission Corporation to promptly stop the flow of natural gas to the rupture.

From its investigation of this accident, the Safety Board identified safety issues in the following areas: public safety near pipelines and steel pipe toughness properties.

As a result of its accident investigation, the Safety Board issued safety recommendations to the Research and Special Programs Administration, the Texas Eastern Transmission Corporation, the American Public Works Association, the Interstate Natural Gas Association of America, the Association of Oil Pipe Lines, the American Petroleum Institute, the American Gas Association, the American Society of Civil Engineers, the International City/County Management Association, and the American Planning Association.

INVESTIGATION

The Accident

The Explosions.--About 11:55 p.m. on March 23, 1994, a 36-inch diameter pipeline owned and operated by Texas Eastern Transmission Corporation (TETCO) ruptured catastrophically on the plant property of Quality Materials, Inc., (Quality) in Edison Township, New Jersey (figure 1). Natural gas, escaping at a pressure of about 970 psig,¹ excavated an elliptical hole² and blew hundreds of feet into the air, propelling pipe fragments and rocks more than 800 feet. Within 1 to 2 minutes of the rupture, one of several possible sources ignited the escaping gas, sending flames that radiated heat in excess of 1,000 degrees Fahrenheit (°F) upward 400 to 500 feet in the air. The radiant heat ignited the roofs and other combustible materials on buildings on the west side of the Durham Woods Apartments (Durham Woods) complex more than 100 yards away from the rupture site.

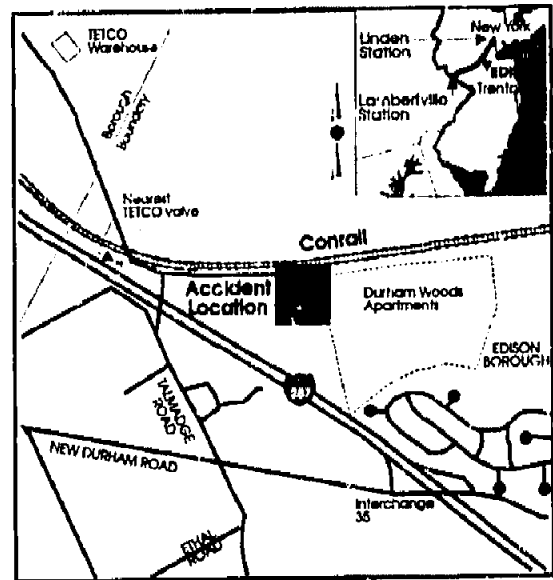


Figure 1.--Drawing of accident area.

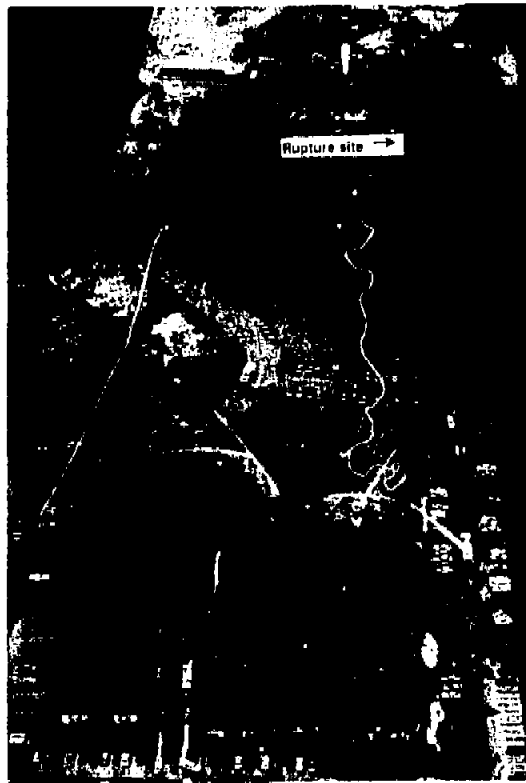
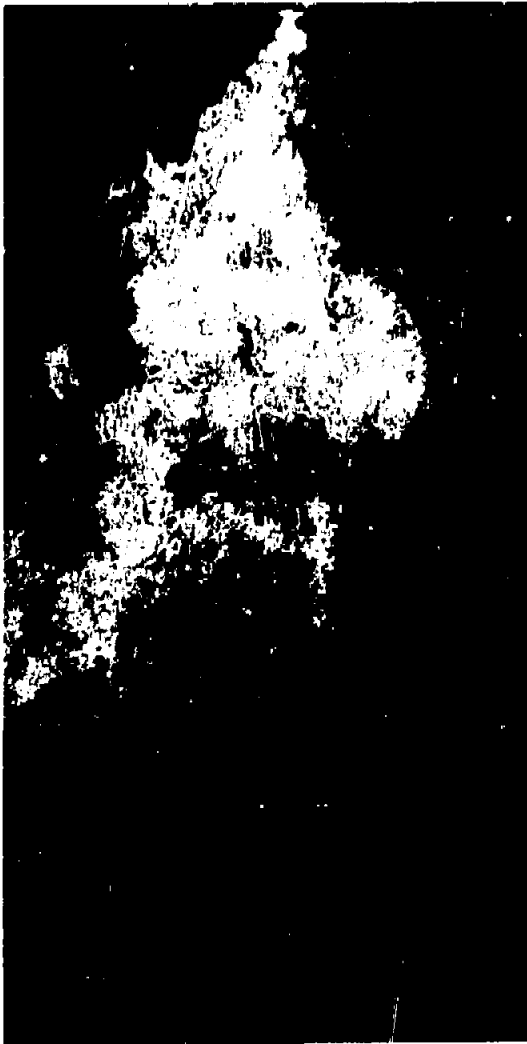
According to a policeman who lived in the complex, the apartment residents were alerted and awakened by a loud explosion-like noise and by flying rocks and debris pelting the outside walls and roofs of their units. He said another loud noise followed, then the sky "lit up like daylight," and "an extreme amount of heat" began to come into his apartment.

The policeman/resident said when he looked outside his unit, "All I could see was a wall of fire, nothing but flames." He grabbed his small son and immediately left his unit. He said, "The inside walls were starting to smoke ... the heat was ... tremendous ... you couldn't even breathe." He pounded on doors to alert others as he ran along the outer walkway. By the time he reached the bottom of the stairs from his third floor unit, the building front was burning.

Many of the 1,500 apartment occupants in the 63 two- and three-story buildings had to escape on foot from the complex. Residents could not flee using automobiles parked on the northwest side of the complex because the fire's heat made the metal too hot to touch, was melting the light lenses and other plastic parts, and was causing glass windows to shatter.

¹ Psig is the pressure measured in pounds per square inch above atmospheric pressure.

² TETCO installed the pipeline about 7 feet deep. Because of soil and other material added above the pipe over the years, the depth of the pipeline at the time of the rupture was about 12 feet. The hole excavated by the rupture extended about 140 feet along the pipeline, was 65 feet wide, and had an average depth of 14 feet.



Figures 2a, 2b, and 2c. (above) The 400- to 500-foot-high gas-fed fire raged for 2 1/2 hours before TETCO could divert the gas flow from the rupture area. (top right) Federal and State investigators observe a backhoe operator uncovering the failed pipe. (right) The accident scene on the following day. Photographs courtesy of *The Courier-News*, Bridgewater, New Jersey.

Postexplosion Events

Community response effort.--About 11:56 p.m., an Edison police officer patrolling in his car reported the accident to his headquarters. Phone company officials estimated more than 200,000 calls were made to the Edison Township "911" in the hour after the rupture.

At 11:57 p.m., the Edison Township Fire Department dispatched three fire engines and one ladder truck, which arrived at the apartment complex about 12:02 a.m. on March 24. Before leaving their station, the firefighters saw the intensity of the fire and called for additional units to respond. According to firefighters, when they arrived at the complex, the building nearest the rupture site, no. 12, was "fully involved" in fire, and three buildings adjacent to it were rapidly becoming involved in fire. When they attempted to get close to building no. 12, the heat from the massive fire cracked the tail light lenses and began to char the paint on one fire truck. Firefighters then moved a short distance south of building no. 12, where they continued fire and rescue operations. They could not suppress the fires in the eight buildings closest to the gas flame, so they concentrated on containing the fires by wetting down adjacent buildings.

Emergency responders established a medical command post and triage area at 12:20 a.m. and an incident command post (CP) at 12:30 a.m. on Talmadge Road, about 3/4 mile from the rupture. The Edison Township Fire Chief served as the incident commander (IC) for all operations and the Edison Police Department staffed the CP. At 12:30 a.m., the IC established a staging area for emergency response personnel and equipment at the Pines Manor Banquet Hall parking lot on Route 27, about 1 1/2 miles from the rupture. By 12:30 a.m., the firefighters were able to prevent the spread of the fire to additional buildings.

TETCO response.--On March 24 at 12:05 a.m., the Supervisory Control and Data Acquisition (SCADA)¹ system at the TETCO Gas Control Center in Houston, Texas, (Houston Gas Control) and at the company's compressor station in Lambertville, New Jersey, received alarms indicating that compressor unit 2 was off-line and unavailable for service at Line 20's Linden Station, an unmanned, remotely-controlled compressor station about 10 miles east of the rupture site. At 12:07 a.m., Houston Gas Control received a call from the Lambertville station operator, who reported that he had received a low suction pressure alarm indicating the no. 2 compressor unit at Linden station was unavailable.² During the conversation, the Lambertville operator remarked, "My God, I can see a fireball in the sky toward Linden." Controllers at Houston Gas Control checked the SCADA computer monitor and observed that the suction pressure on Line 20 at Linden station had dropped from a normal operating pressure of about 960 psig to about 300 psig and was continuing to fall. Houston controllers then notified appropriate TETCO management of the emergency.

The Lambertville senior operator notified the station supervisor at home, who instructed on-duty personnel to call out personnel assigned in the South Plainfield, New Jersey, area. The Lambertville station operators instructed some off-duty TETCO personnel to assemble at the TETCO South Plainfield office, which was within 1 mile of the rupture, and other personnel to report to specific valve locations (see figure 3). During his drive to the South Plainfield warehouse, the station supervisor radioed personnel to determine who was available to respond and to instruct them on what to do. When area employees arrived at the South Plainfield office, they

found the electricity and telephones were not working. Upon arriving at the South Plainfield office, the supervisor used his vehicle radio to instruct personnel on closing two valves downstream of the rupture site and one valve upstream. Employees dispatched downstream arrived at no. 20-88 near Route 1, about 5 miles northeast of the rupture, at 1:00 a.m. and no. 20-122 at the Hanover tie-in near no. 20-88 at 1:10 a.m. They closed no. 20-88 by 1:35 a.m. and no. 20-122 by 2 a.m.

About 1:10 a.m., three employees were dispatched to the closest upstream valve, no. 20-83, which was about 2,000 feet from the rupture site. Upon arriving at valve no. 20-83 about 1:15 a.m., they found the pressure in the pipeline had diminished to the point that it was too low to operate the gas-power assist motor on the valve-closing mechanism. The employees then attempted to close the valve manually. They said that as they attempted to close the valve gate through the 36-inch-diameter pipe, the unequal pressures on either side of the gate made the valve, which takes about 700 to 750 revolutions to close, increasingly difficult to turn. About 1:30 a.m., they gave up on trying to close valve no. 20-83 and notified their supervisor.

The supervisor then instructed personnel who had gathered in the Edison area to proceed upstream to close the next valve, no. 20-77 at River Road, which was about 5 miles southwest of the rupture site. The pipeline crew experienced difficulty getting to the River Road valve because the traffic (community responders and gawkers) had become extremely heavy, especially at an emergency roadblock on Route 27. Shortly after 2 a.m. they reached valve no. 20-77 at the Raritan River. They were able to close no. 20-77 by 2:25 a.m. The closure of the River Road valve enabled employees at valve 20-83 to fully close it, which isolated gas from the rupture area and allowed the gas-fed fire to self-extinguish.

The TETCO response team from Houston arrived at Edison about 8:15 a.m. and established a TETCO CP to facilitate investigation of the accident, to assist the residents who had been displaced, and to determine how to meet the supply needs of its customers north of Edison. TETCO officials said that because the accident occurred during relatively warm temperatures, the disruption to consumers in New Jersey, New York City, New York, and New England States was not as significant as it could have been had the rupture occurred in cold weather.

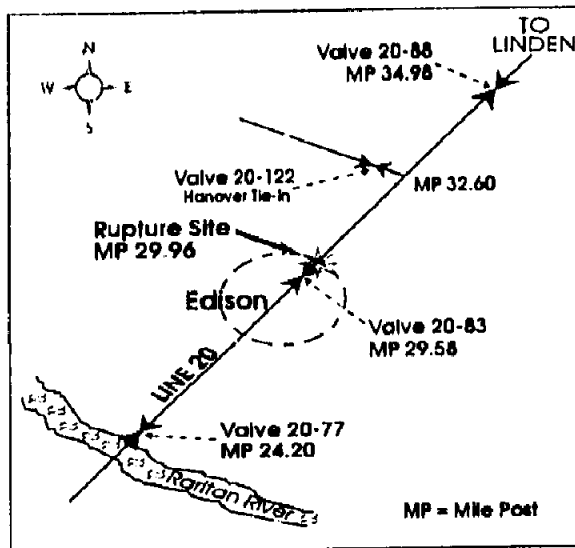


Figure 3. Valves closed by TETCO employees.

Injuries.--Table 1 categorizes the injuries sustained in this accident according to the International Civil Aviation Organization injury code.⁵

Medical and Pathological Information.--

Emergency responders evacuated 29 apartment residents to area hospitals, where two individuals were admitted for treatment: one for a broken leg and one for smoke inhalation. Seventy-three apartment dwellers reportedly were treated for minor injuries by area hospitals or private physicians and released the same day. Most of the injuries sustained by residents were minor foot burns from the hot pavement and foot cuts from the glass shards of exploding car and apartment windows. No apartment resident suffered a fatal injury. However, a woman, who had a history of heart trouble, reportedly suffered a fatal heart attack while viewing the fire from her residence, which was about 1 mile from the site.

Table 1.--Reported injuries

Injury Type	Public	Other	Total
Fatal	0	0	0
Serious	2	0	2
Minor	100	10*	110
Total	102	10	112
* Firefighters			

Pipeline Damage.--The rupture destroyed about 75 feet of pipe and released about 297 million standard cubic feet of natural gas.⁶ Approximately 220 feet of pipe was ultimately replaced. Line 20 was out of service for 21 days. TETCO estimates that its cost of the lost gas and the pipe repairs will be about \$2.5 million.

Other Damage.--Other parties reporting losses from the rupture, fire, and/or radiant heat included the following:

Buckeye Pipe Line Company (Buckeye) reported having to shut down and inspect two liquid pipelines located north of the railroad tracks at the asphalt plant to ensure that the lines had not been damaged by the heat from the fire. The two lines transported about 200,000 barrels per day of refined petroleum products. Buckeye estimated its loss at \$94,000.

Consolidated Rail Corporation (Conrail) estimated the damage to its track from the fire and radiant heat was \$250,000.

⁵ Title 49 Code of Federal Regulations (CFR) 830.2 defines *fatal injury* as "Any injury which results in death within 30 days of the accident" and *serious injury* as an injury that "(1) Requires hospitalization for more than 48 hours, commencing within 7 days from the date the injury was received; (2) results in a fracture of any bone (except simple fractures of fingers, toes, or nose); (3) causes severe hemorrhages, nerve, muscle, or tendon damage; (4) involves any internal organ; or (5) involves second or third degree burns, or any burn affecting more than 5 percent of the body surface."

⁶ TETCO officials estimated the amount of gas lost would supply the needs of a 250,000- to 300,000-person community on an average winter day.

Public Service Electric and Gas Company reported damages of \$130,253 to electric and \$61,865 to gas facilities. Electric damage was to poles and overhead construction; gas facility damage included 2 plastic mains, 22 services to the buildings destroyed in the fire, and numerous gas meters and regulator sets.

Quality estimated the damage to its equipment and plant inventory was \$5.5 million and its loss of commerce was \$2.5 million, for a total loss of \$8 million.

The Durham Woods owners estimated the loss of eight apartment buildings, the severe damage to six buildings, and the minor damages to several other buildings was \$12.4 million.

Durham Woods residents estimated the damage to about 250 destroyed or severely damaged vehicles totalled \$2 million. Durham Woods residents also suffered various losses to personal property, which have not been estimated.

The Town of Edison estimated the cost of the emergency response effort was \$250,000.

Postaccident Site Inspection

Most of two pipe sections, about 75 feet of pipeline, had fragmented and been propelled as far as 800 feet from the rupture site. After observing scratches and other mechanical damage markings on the outer walls of large pipe fragments in the rupture area, investigators and TETCO personnel searched the entire accident scene to locate as many pipe fragments as possible and recovered 23. The closest fragment to the apartment complex was about 70 feet west of building no. 24 (see figure 4). Investigators and metallurgists visually examined and documented dents, gouges, and other significant marks on the recovered fragments and a damaged area of pipe still attached to the pipeline. Based on a reconstruction of the recovered pipe fragments (Appendix B), the National Transportation Safety Board (Safety Board) was able to examine all but three small portions of both pipe sections. Additional information about the metallurgical examination appears later in this report.

The 1-inch thick somastic pipe coating contained areas of damage, including "teeth marks," on the south side of the pipeline east of the rupture. The center-to-center spacing was 0.8 of a foot between some teeth marks and 0.9 of a foot between others. At the top of the pipe, the pipe coating was disbonded in some areas; however, the pipe metal showed no evidence of being gouged in the areas of coating damage.

The hole created by the rupture exposed old tires and plastic pipe pieces in the soil adjacent to the pipe. Because of the debris and the damages found to the pipe, TETCO had a contractor excavate the pipe in both directions until company officials were satisfied they had identified all damaged pipe. In the course of uncovering about 75 feet of pipe west of the rupture, crews found little debris. However while excavating east of the rupture, they unearthed a great amount of debris above and around the pipe, including tires, empty drums and buckets, plastic pipe pieces, an old conveyor belt, large metal chains, a two-drawer file cabinet, and leaking drums.

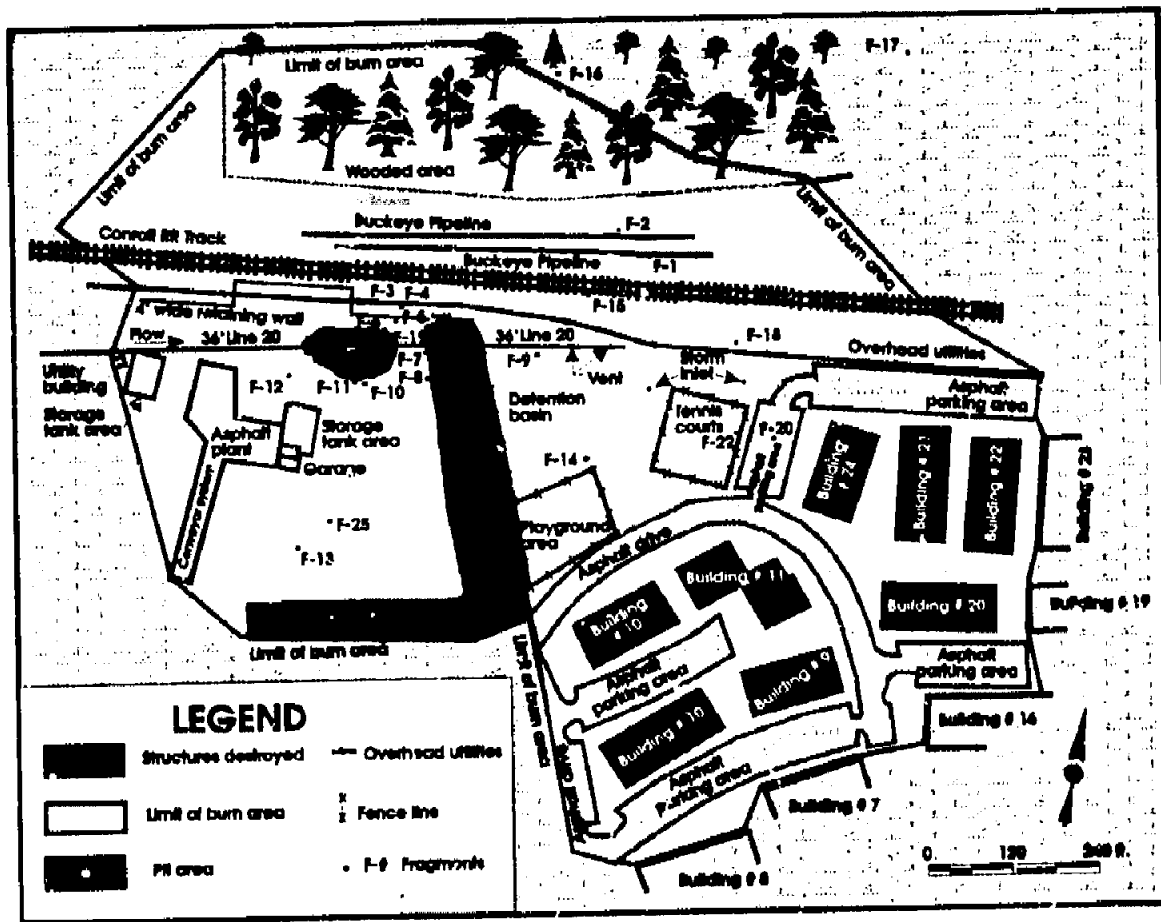


Figure 4. Location of pipe fragments.

When investigators discovered the leaking drums, the Middlesex County, New Jersey, Hazardous Materials Unit and the New Jersey Department of Law and Public Safety declared the rupture site a potential crime scene, cordoned off the area, and assumed control of the excavation and documentation activities. Crews continued excavating east through the earthen berm along the plant's east property line until they no longer unearthed any debris. The work securing and documenting debris from the rupture site continued through April 21, 1994. State investigators documented more than 400 items buried near Line 20, many of which were at the same depth as the pipeline. The recovered items were categorized as vehicle parts (tires, filters, wheels, etc.), office equipment and supplies (chairs, desks, drink vending machine, etc.), building parts (steel channels, steel reinforcement bars, steel sheet metal, concrete foundation pieces, etc.), machine equipment supplies (fluids in drums, conveyor belts, chain drives, rubber pressure hoses, etc.), and plant equipment and facility parts (cast-iron front of an asphalt rotary oven, manhole covers, electrical control boxes, electric motors, etc.). In addition, while excavating about 20 feet south of the pipeline to prevent an earth slide, crews uncovered a crushed Ford Ranger pickup that had been reported stolen in 1990.

Personnel.--Before Federal, State, or TETCO officials conducted an on-scene inspection of the rupture area, TETCO ordered the two Lambertville operators and the three Houston controllers on duty at the time of the rupture to submit urine samples for drug testing as required by 49 CFR 199.11.⁷ On March 24, 1994, the Lambertville operators provided samples about 8 a.m. Eastern Standard Time and the Houston controllers provided samples between 2:30 and 3:10 a.m. Central Standard Time. The results of the tests were negative. Additional information about employee operating procedures appears later in this report.

Pipeline System Information

System Ownership/Organization.--TETCO is one of four interstate pipeline subsidiaries of Panhandle Eastern Corporation (PEC), whose interconnected pipeline network accesses most natural gas producing basins in North America. Within the contiguous United States, PEC has more than 26,000 miles of natural gas pipelines. The corporation's primary markets, which span the Mid-Atlantic, New England, and Midwest States, account for one-third of domestic gas consumption. In 1993, gas consumption in the United States exceeded 20.2 trillion cubic feet.

In 1948, TETCO became the first pipeline company to deliver Gulf Coast natural gas to Mid-Atlantic markets. Today, TETCO has about 10,000 miles of pipeline extending from the Texas/Mexico border to New York City. According to PEC's 1993 annual report, TETCO figures predominantly in a number of its parent corporation's expansion plans, especially in the northeastern states.

Line 20 History.--In the early 1960s, TETCO decided to increase the capacity of its natural gas pipeline system to the northeastern states by adding a 36-inch "New Jersey Loop" pipeline, which it designated Line 20, between Lambertville and Staten Island, New York. The U.S. Federal Power Commission, the predecessor of the U.S. Department of Energy's Federal Energy Regulatory Commission, granted TETCO a Certificate of Public Convenience and Necessity under the Natural Gas Act to construct and operate the line.

Routing.--The design route of the new pipeline paralleled the route of two existing TETCO 20-inch pipelines east from Lambertville for about 30 miles. According to a TETCO official, in eastern New Jersey where residential development had substantially increased after the 20-inch lines were constructed, the company designed the latter segment of Line 20 to veer away from the two 20-inch lines through less developed areas. Before building the line, TETCO analyzed ten potential routes for the pipeline in an effort to avoid residential areas. Even after construction began on the line, TETCO continued to make design changes to the route when it identified that residential areas were being developed near the proposed pipeline course.

TETCO designed the pipeline in compliance with Section 8 of the *American Standard*

⁷ The CFR requires, "As soon as possible but no later than 32 hours after an accident, an operator shall drug test each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident." TETCO ordered the testing in the event it was later determined that the pipe ruptured as a result of an over-pressure condition.

Code for Pressure Piping, 1955 Edition (ASA code), industry specifications published by the American Society of Mechanical Engineers.⁸ As one criteria to ensure a pipeline was designed "to be adequate for public safety" and to determine the stresses for which a pipe is designed, the ASA code required that population indices be determined for each 1-mile and each 10-mile stretch of a pipeline route.⁹ Based on the location classifications described in the ASA code, the density indices along the proposed route of Line 20 were primarily Class 2. (Table 2 paraphrases the location classifications in the ASA code.)

TETCO also had to comply with State standards. New Jersey regulations require that pipelines operating at more than 500 psig be designed to meet ASA code safety standards for Class 3 or Class 4 areas if they are within a specified distance of certain structures as noted below:

Class 3 - Within 500 feet of (1) a residence; (2) a building used for public gatherings; (3) a school, playground, or building devoted to institution use; or (4) property zoned as residential; or (5) a building devoted to a business that employs more than 3 people.

Class 4 - Within the boundaries of or within 25 feet of a railroad right-of-way or a public hard surface highway or street.

In anticipation of increased residential development within 500 feet of the proposed pipeline, TETCO elected to construct Line 20 to Class 3 design criteria except for the approximately 7 miles in which the locations met New Jersey Class 4 design criteria.

Table 2. ASA location classifications

Class 1	One or a combination of the following land types having a 10-mile density index of 12 or less and a 1-mile density index of 20 or less: wastelands, rugged mountains, deserts, grazing land, and farm land.
Class 2	Fringe areas around cities and towns and farm or industrial areas where the 1-mile density index exceeds 20 or the 10-mile density exceeds 12 and which do not meet Class 1 or Class 3 criteria.
Class 3	Residential and commercial areas where 10 percent or more of the lots are on or abut the intended pipeline right-of-way and which do not meet Class 4 criteria. This class includes areas completely occupied by commercial or residential buildings three stories or less.
Class 4	Areas where buildings having four or more above-ground floors are prevalent, where traffic is heavy or dense, and where other underground utilities may be numerous.

⁸ *The American Standard for Gas Transmission and Distribution Piping Systems, ASA B31.1.8-1955*. When Line 20 was constructed in 1961, no Federal safety standards governed natural gas pipelines. Current Federal standards for pipeline design, construction, and initial testing do not apply to lines built or in operation before the Federal requirements became effective in 1970.

⁹ Paragraph 841.001, ASA B31.1.8-1955, indicates that the number of buildings intended for human occupancy within 1/4 mile of either side of the pipeline for a distance of 1 mile is the 1-mile density index; the sum of ten 1-mile indices divided by 10 is the 10-mile density index. When computing the 10-mile index, any 1-mile index exceeding 20 is counted as 20.

Route through accident area.--On June 28, 1960, TETCO obtained an easement from the land owners to construct a pipeline across the north portion of an 8-acre tract abutting the railroad right-of-way near milepost (MP) 30. TETCO designed this segment of Line 20 to Class 3 specifications. TETCO recorded the right-of-way agreement and a drawing of the pipeline path that the pipeline company negotiated with the property owners with the Middlesex County Clerk's office. The drawing showed that from the west, the pipeline entered the property at a point about 41 feet south of the northwest corner. The line ran east for 636.5 feet, whereupon it turned northward about 17 degrees and continued eastward for 219.5 feet, where it exited the east property line 40 feet south of the northeast property corner. Within the tract, the pipeline was located more than 25 feet from the railroad right-of-way and was buried about 7 feet deep.

At the time TETCO designed the Line 20 segment through the accident area, a plant operated by Edison Asphalt Corporation was located on the property (see figure 5). When TETCO built the pipeline through the property in 1961, it buried the line primarily beneath the plant roadways. The eastern portion of the pipeline passed just north of a settling pond used to collect plant processing sediment. (Additional information about the history of the asphalt plant operations and expansion of the pond appear later in this report.)



Figure 5. 1961 aerial of accident area. Dotted line shows route of pipeline.

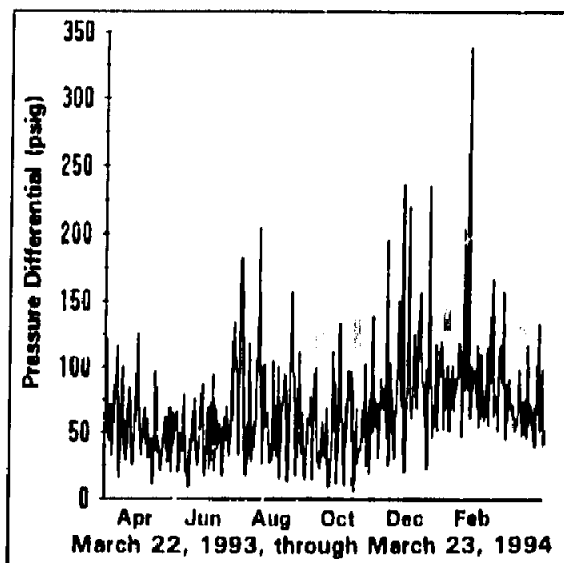
Pipe Specifications.-TETCO contracted Bethlehem Steel Company to manufacture the 36-inch diameter pipe to American Petroleum Institute (API) Standard 5L for Grade 52 (52,000 pounds per square inch (psi) specified minimum yield strength [SMYS]) steel pipe. The wall of pipe used in Class 3 locations was 0.675 inch thick; the wall of pipe used in Class 4 locations was 0.844 inch thick. In the area of the 1994 rupture, the pipe wall thickness was 0.675 inches.

The ASA code required that any pipeline to be operated at 30 percent or more of the metal's SMYS be field tested to prove strength after construction and before being placed in operation. The standards stipulated that pipelines in Class 3 and Class 4 locations be tested hydrostatically to a pressure not less than 1.4 times the maximum operating pressure of the pipeline. The maximum operating pressure of Line 20 was calculated at 975 psig; therefore the minimum pressure required to test the line was 1,395 psig.⁸ In 1961, TETCO elected to test Line 20 at 2,048 psig, which stressed the pipe metal in this area to 105 percent of its SMYS.

At the time Bethlehem Steel Company manufactured the pipe lengths for Line 20, neither the API standards or the ASA code addressed the toughness⁹ properties of the steel used. The API standard for pipeline steels and the Federal standards that superseded the ASA code still do not specify toughness properties for the steel in pipes. The current API standard does have Supplementary Requirement 5 (SR5) that provides fracture toughness test procedures for pipe 4.5 inches in diameter and larger. Although not required, purchase orders may include specific toughness properties for the steel used in manufacturing pipe. Pipeline operators can require the manufacturer to use the SR5 test procedures to verify the pipe's toughness properties.

Before it was put in service, Line 20 was coated externally to electrically isolate the steel pipe from the soil to minimize the potential of corrosion. TETCO also installed a corrosion protection system to further minimize the potential of corrosion.

Subsequent pressure variances.--TETCO began operating Line 20 during the last quarter of 1961 to provide gas to customers between Lambertville and Staten Island. As customer demand grew, Line 20 experienced more and greater pressure changes. Throughout the years of operation before the accident, Line 20 frequently experienced pressure differentials from 200 to 350 psi. Graph 1 shows the typical pressure changes for the year preceding the rupture.



Graph 1. Line 20 pressure changes 1993-1994.

⁸ ASA B31.1.8, Chapter IV, Section 841, paragraph 841.1 contains the design formula for calculating the maximum allowable operating pressure of a pipeline; ASA B31.1.8, Chapter IV, Section 841.412 (c) contains the pressure testing requirements for Class 3 and Class 4 pipelines.

⁹ Toughness is the ability of a material to absorb energy and to deform plastically.

Valves.--The ASA code stipulated that valves be installed on transmission lines to allow sections to be shut down or isolated from the pipeline and be spaced depending on the classification of the area in which the pipeline is located (see table 3). The ASA code did not address using any specific type of valve as a safety mechanism. In fact, ASA B31.1.8-1955, Paragraph 848.21(d) states "This code does not require the use of automatic valves, nor does the code imply that the use of automatic valves presently developed will provide full protection to a piping system. Their use and installation shall be at the discretion of the operating company." The code did not mention remote-operated valves. Its only reference on use of valves in respect to emergencies states, "Pipeline valves that might be required during an emergency shall be inspected periodically and partially operated at least once per year to provide safe and proper operating conditions."¹⁰ Through the area encompassing the accident site, TETCO installed more valves per mile than required for Class 3 locations.

Table 3. ASA required valve spacing

Location Class	Maximum distance between valves
1	20 miles
2	15 miles
3	8 miles
4	5 miles

Source: ASA B31.1.8-1955, Paragraph 848.11.

According to the TETCO senior vice president, the company uses manually operated gate valves on much of its system, including the Line 20 segment, because they provide positive shut off, are easy to maintain, stand up to wear, and are not easily damaged when running internal cleaning or inspection devices. Excluding check valves at the stations, remote control valves (RCVs) at meter stations, and main line automatic control valves (ACVs) that were already installed on a lateral line purchased by TETCO, the company has not installed RCVs and ACVs on its main line system. The TETCO senior vice president stated, "Our history with automatic-operated valves and our knowledge of others who have used them has not been real good." He stated that ACVs, which usually actuate on a rate of pressure change across the valve, had been known to close unexpectedly without cause, which creates major safety problems.

The TETCO official stated that in planning Line 20, the company designers considered not only day-to-day operations, but also emergency situations. They then designed a valve closing mechanism that combined a large gear wheel with a relatively small motor to facilitate closing the "gate" through the 36-inch diameter pipe under any condition in which the upstream pressure is within the design of the valve. The larger wheel requires less force to turn; the gas-driven motor powers the turning of the gear. With or without the closing mechanism, moving a valve from the fully open to the fully closed position on the 36-inch diameter line requires about 700 turns of the gear wheel.

Operations and Maintenance

General Safety Requirements.--The industry engineers drafting the 1955 ASA code took

¹⁰ See ASA B31.1.8-1955, Paragraph 856.1.

the position that prescribing operating procedures adequate for public safety "in all cases" was "impractical." The 1955 ASA code therefore identified "basic requirements" for promoting pipeline safety, which included having a plan for employees that provides detailed operating procedures and instructions for both normal and emergency conditions; operating facilities in conformance with the plan; keeping records necessary for administering the plan; and modifying the plan as dictated by "exposure of the public to the facilities and changes in operating conditions...." The code did not specifically define actions for complying with its requirement, but did advise operators, "Particular attention should be given to those portions of the facilities presenting the greatest hazard to the public in the event of an emergency or because of construction or extraordinary maintenance requirements."¹¹

Federal gas pipeline safety standards (49 *CFR* 192) evolved from the 1968 ASA B31.8 Code and today many remain relatively unchanged from similar provisions of that Code. Like the ASA code, Federal standards contain general provisions rather than specific procedures for ensuring the safe operation of gas pipelines. Federal regulations applicable to Line 20 are provided in Appendix C.

Monitoring and control regulations.--The 1955 ASA code contained no specific requirement to monitor the pressures, temperatures, and other operational parameters of remote-controlled gas transmission pipelines to promptly alert the operator of abnormal conditions including out-of-specification operations, such as line ruptures. Until February 1994, Federal regulations for natural gas pipelines contained no specific requirement to monitor pipelines to detect abnormal operations. On February 11, 1994, the Research and Special Programs Administration (RSPA) issued 49 *CFR* 192.605 (a) requiring operators to develop a program for handling abnormal operations on gas transmission lines; however, the regulation does not contain directions as comprehensive as the monitoring requirements for liquid pipelines. The 49 *CFR* 195.402(b)(9) requires that liquid pipeline operators be able to detect abnormal operating conditions in certain facilities not equipped to fail safe "by monitoring pressure, temperature, flow, and other appropriate operational data and transmitting this data to an attended location." Even though liquid regulations contain a more defined general objective, they do not specify the accuracy, timeliness, or other criteria an operator must meet to satisfactorily meet the objective.

Control of the TETCO system.--The TETCO pipeline system is controlled and monitored by the combined activities of personnel at Houston Gas Control and by station operators at manned stations. Through the accident area, Line 20 is controlled both by the combined actions of Houston Gas Control and by operators at Lambertville station.

Houston Gas Control determines which gas compressor stations and/or compressor units at Lambertville and Linden stations operate, the preferred level of operation of each unit, and the basic arrangement of the pipeline valves and regulators necessary to provide the gas volumes ordered by customers. Houston Gas Control remotely controls about 20 percent of TETCO's gas compression equipment by entering a series of operating set points into the automated control systems for each of the various stations along the pipeline. The physical control of stations along

¹¹ See ASA B31.1.8-1955, Paragraph 850.4(c).

the line is accomplished by staffed facilities. Lambertville station operators control the equipment on Line 20, including the gas compressor units at the unmanned Linden station. Houston Gas Control advises station operators at Lambertville regarding daily orders from customers and other necessary changes in valves or pressure settings at the Lambertville and Linden stations, and the Lambertville operators will accomplish the tasks. Gas Control monitors the operation of the pipeline and advises the operators at Lambertville station to make any modifications necessary to accomplish the requested gas volume deliveries.

Gas Control and the local station operator receive readings associated with the basic pipeline operating parameters, pressures, temperatures, and status of compressor units. Both Gas Control and Lambertville station receive an indication when the computer detects a monitored parameter exceeding an operational set point; but, both do not receive equivalent information on the reason for the alarm. For example, Lambertville station will receive an alarm plus an indication as to what monitored parameter is not within the normal operating range established by TETCO (see table 4). At the same time, Gas Control receives the alarm, but does not receive information on the type of alarm generated or the

Table 4. Pressure alarm parameters

Alarm Type	Operating Parameters
High	1 pound above maximum allowable operating pressure for the station site
High-High	2 percent above the <i>high</i> parameter
Low-Low	10 pounds above the emergency shutdown device (ESD) pressure for a facility
Low	4 percent above the <i>low-low</i> parameter

reason for the alarm. Gas Control primarily receives alarms on those monitored parameters considered critical to the continued safe operation of the pipeline, such as detection of gas or flames at compressor stations, activation of the compressor station emergency shutdown, and unavailability of compressor units.

Events following the rupture.--Immediately after the pipeline ruptured on March 23, 1994, neither Gas Control nor Lambertville station received a low-pressure alarm indicating that compressor suction pressure at Linden station had dropped below normal operating limits or a low-low alarm indicating the suction pressure was nearing a level low enough to trigger automatic shutdown. The first alarm each received was at 12:05 a.m. on March 24, 1994, when compressor unit 2 at Linden station automatically shut down due to low suction pressure.

After reviewing the alarm system for Lambertville and Linden station, TETCO determined that during the weekly update to the monitoring system computer data base, a programmer at Houston had input the alarm set points at zero in accordance with his normal operating procedures. TETCO officials explain that it was company procedure for programmers not to set low pressure set points each time they updated the data base because low set points are unique for each station. After a programmer updated the data base, the gas control supervisor in Houston set the low pressure alarms and checked the high pressure alarms to ensure they were correct. In this instance, a gas control supervisor did not set the low pressure alarms.

The TETCO Director of Gas Control stated that inactivation of the two low suction pres-

sure alarms monitoring gas pressure to Linden station did not directly affect the gas controllers' actions at the time of rupture. He explained that the alarms alert Gas Control to changes in the system operation and to when certain parameters are different than the limits set; but, they do not limit access to information or to when the information is received. He estimated, based on previous experience, that the failure to receive the low pressure alarms delayed an operator recognizing the abnormal operating condition no more than 3 minutes.

The Director of Gas Control added that TETCO's ability to identify problems and their locations between compressor stations is a function of the locations from which the monitoring system collects data along the pipeline. He stated that the data collected are received primarily from compressor stations. The only other data associated with a pipeline segment between compressor stations would be that obtained from the receipt and delivery meters between the stations. Houston Gas Control does not have the capability to remotely operate any main line valves. To isolate a failed pipeline segment, TETCO must dispatch employees from their present locations to the valve locations to manually close the valves.

Regarding the time needed to close main line valves, the Director of Gas Control stated that Houston Gas Control maintains telephone numbers for emergency use and that they are able to initially notify employees within 5 to 10 minutes. The time required to actually close a specific valve depends on an employee's travel time to the valve considering the traffic and weather conditions at the time, and the time required to physically operate the valve. He said that while the company had not identified the typical employee travel interval, in his experience with the TETCO system and alarms (rather than with prior pipeline accidents), it takes about 15 to 20 minutes for an employee to travel to the valve. He added that in some instances it has taken more than 1 hour for an employee to arrive at a valve after being dispatched.

Postaccident actions.--To prevent its systems from again being operated without functioning low pressure alarms, TETCO modified its procedure on updating its computer control program. Its gas control group now provide its systems group with a copy of the program used to operate the system. The systems group make needed data base changes to the copy without altering the alarm set points. With this procedure, the low pressure alarm setting is functional when the new program is installed. The gas control group modifies the settings only if it makes changes to the system operations.

Patrolling Requirements.--Federal standards require that transmission pipeline operators have a patrol program to observe surface conditions on and adjacent to their pipeline rights-of-way for indications of leaks, construction activity, and other factors affecting safety and operation. The operator is to determine the frequency of patrols for a pipeline based on the size of the line, the operating pressure, the class location, the terrain, the weather, and other factors; however, in Class 3 locations, patrols at highway and railroad crossings must be made four times per calendar year at intervals not to exceed 4 1/2 months and at all other locations twice each year at intervals not to exceed 7 1/2 months.¹² In the accident area, patrolling was required twice a year.

¹² See 49 CFR 192.705.

Aerial patrols.--Except in selected urban areas such as Newark, New Jersey, which are restricted to air traffic and must be patrolled by a surface vehicle, TETCO conducted, weather permitting, weekly air patrols along its buried system. In New Jersey during the spring and summer when construction activity was greater, TETCO increased its aerial surveillance to twice a week. Although Federal minimum safety standards do not require that TETCO conduct aerial patrols, company officials stated that they believe the patrols are essential to identify activities that might endanger their pipeline, such as excavation or erosion. Initially, TETCO contracted an air patrol service for this work. The contract specified standards regarding what the pilot should observe and report to the company by radio and required that he provide weekly written reports of his observations. Additionally, the contract pilot was required to visit the TETCO area office monthly to discuss the aerial patrols with the Area General Manager. The contract also reserved the right of TETCO to have a company representative fly with the pilot during the aerial patrol. In 1989, TETCO purchased its own planes and employed pilots to perform the patrols to ensure better control and understanding of the pilots' abilities and training.

The pilots fly single-engine, fixed-wing aircraft over geographic areas of the pipeline, such as Edison Township. The pilot who flies the New Jersey portion of the pipeline system has flown that route since 1989. He flies at altitudes between 500 and 1,000 feet above ground level, depending on the topography and the congestion within the area. Each time he flies a survey patrol, he monitors not only the 41-mile-long Line 20, but also more than 700 miles of other pipelines in five states: Ohio, Pennsylvania, New Jersey, New York, and Maryland. Although TETCO has not performed a study to evaluate the adequacy of its flight surveillance, the TETCO general manager of field operations stated that he has flown with the Line 20 survey pilot to observe patrol activities. It was the general manager's assessment that the pilots have sufficient ability to observe the pipeline to detect evidence of leakage or excavation. He did not believe it necessary, even in urban areas where pilots have to avoid obstacles such as electric power lines, radio towers, and multi-story buildings, to include a second person on the air patrol crew to adequately monitor activities along the pipeline route.

When a pilot observes construction activity near the pipeline, he radios the nearest TETCO field office and reports the type and location¹³ of work to TETCO ground crews. If personnel at the local office are aware of the activity, neither the pilot nor the field personnel make a record of the report. However when the field personnel are not aware of the reported activity in an area, they record the report, travel to the area, contact the person performing the excavation, install temporary stakes and flagging to mark the precise location of the pipeline route, caution the excavator about excavating near the high pressure pipeline, and remain on site during excavation to ensure the safety of the pipeline. The TETCO Area Superintendent stated that the air patrol would not report activities occurring within the plant compound, including excavation activities, because the pilot would associate the truck traffic in and out of the plant, the moving of material stockpiles, and the excavation equipment at the plant as part of the day-to-day plant operations. Representatives from TETCO, RSPA, and the State of New Jersey reviewed aerial patrol records dating from 1968 for the pipeline segment crossing the asphalt plant and noted no reports of any excavation activity.

¹³ Pilots identify the location of activity by referencing markers along the pipeline.

The TETCO supervisory pilot trained the survey pilots to look for conditions that might impact the safe operation of the pipeline, such as soil erosion, signs of excavation in process or newly completed, and changes in the soil and vegetation that might indicate a gas leak. A survey pilot's training begins on the ground when he accompanies field personnel along the pipeline route to learn the landmarks along the pipeline and the types of activities that potentially endanger the pipeline. Field personnel then fly with the pilot to ensure that the pilot correctly recognizes the pipeline route from the air. TETCO management personnel fly with a pilot several times a year to assess the adequacy of his patrol. The Safety Board determined from interviews with the Line 20 pilot that his training did not include specific instruction related to industrial areas traversed by the pipeline.

In October 1994, a Safety Board engineer accompanied the TETCO pilot on his routine patrol of Line 20 from Edison to Linden station. Flying at the usual survey altitude of about 550 feet at a speed of about 85 knots,¹⁴ the Safety Board investigator noted the pilot's capability for making observations of the pipeline route and adjacent activities. The investigator reported that the pilot was able to clearly follow the route of the pipeline and identify all significant activities occurring within the right-of-way.

Routine maintenance inspections.--TETCO also conducts routine maintenance inspections near the asphalt plant. Annually, TETCO employees were at test stations on each side of the asphalt plant to make electrical tests of the pipeline corrosion protection system. One such test station was located near the asphalt plant's property line just east of the earth berm and another was just west of the plant. Other TETCO employees annually performed maintenance on a main line valve located west of the intersection of the plant entrance road and Talmadge Road.

In December 1993, TETCO personnel conducted an instrumented gas leakage survey of Line 20. Although not required by Federal minimum safety standards for pipelines transporting odorized natural gas, TETCO performs the surveys every 5 years. During the 1993 survey, TETCO employees with gas leak detection equipment physically walked the pipeline route, including the area through the asphalt plant property. They were instructed to observe the pipeline easement for unusual conditions and activities. Although it is not known whether the TETCO employees conducting the leakage survey actually contacted anyone at the plant, TETCO management stated that company procedures require pipeline employees coming in contact with a property owner or plant operator to make them aware of where the pipeline is located, what the TETCO employee is doing, why TETCO needs access to the property, and whom to contact should any questions or problems arise. The TETCO employees who perform the surveys have in their vehicles information booklets about the pipeline and what to do in an emergency for the land owners and others along the pipeline route. The actions taken by TETCO employees relative to contacts within the asphalt plant are not recorded and those employees filed no report on unusual activities occurring within the asphalt plant.

Internal Inspection of Line 20.--In 1967, TETCO began to supplement the monitoring of its corrosion protection system by conducting internal inspections of its pipelines using a

¹⁴ According to a TETCO official, the usual patrol speed is between 70 and 75 knots.

magnetic-flux leakage instrument, one of several types of inspection devices commonly called a "smart pig" (see figure 6). Testing technicians insert and remove the smart pig into and from the pipeline at specially constructed traps along the main line. The entry trap is called a launcher and the exit trap is called a receiver. Once in the line, the smart pig is propelled by the gas stream, which the technician regulates to a velocity of between 0.5 and 7 mph.

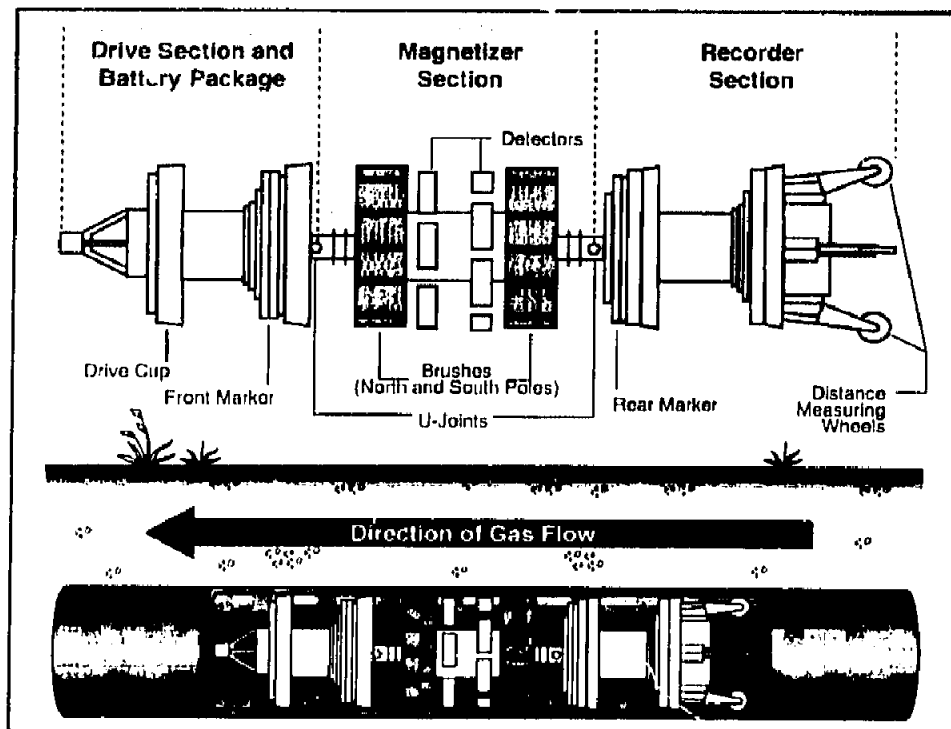


Figure 6. Top shows components of a magnetic flux leakage inline inspection tool, or smart pig; bottom shows a cutaway of a pipeline containing a smart pig.

As the smart pig moves through the pipeline, it induces an electromagnetic field through the entire pipe wall. Detection sensors, spread evenly and overlapping, cover the entire internal circumference of the pipe. The sensors detect any distortion in the magnetic field as an indication of wall thickness variation, and the variations are recorded on magnetic tape within the smart pig. Technicians then convert the taped information to a log from which experienced interpreters identify the physical characteristics of pipe, such as girth welds, dents, and wall metal loss. The smart pig does not directly measure the amount or area of metal loss; rather, a techni-

cian must infer the degree of metal loss from measured changes in the magnetic field.¹⁵ Since 1967, TETCO had internally inspected about 90 percent of its 10,000-mile system, at an estimated current cost of \$1,200 per mile.

Numerous pipeline and site-specific conditions can cause the accuracy of the metal loss and detected characteristics to vary; therefore, in the early years of pigging, the tester had to determine the correlation between the metal loss indication with actual conditions to make an accurate interpretation. As a corroborative measure, TETCO examined the graph produced by the detection instrument, selected an area where metal loss was indicated, determined its location along the pipeline, and excavated the area to measure and correlate the actual conditions with the indications on the graph. Using this information, technicians interpreted with reasonable accuracy the locations, areas, and depth of metal loss, and other indications. In 1986, a TETCO official estimated that the metal loss indications recorded on the in-line inspection device graphs were about 95 percent accurate.

When it began using internal inspection devices, TETCO developed a grading system (see table 5) to assist its employees in uniformly evaluating the severity of the indications. According to TETCO officials, the grading system has enabled the company to respond promptly to anomalies that might compromise the integrity of the pipeline, to schedule inspections for those that appeared significant, and to take necessary remedial action, such as improving the corrosion control system, for indications that do not appear to adversely affect the pipe integrity.

Table 5. TETCO anomaly grading system

Grade	Wall Thickness Loss and Description of Anomaly	
3+	Greater than 50%	Massive, concentrated, interconnected areas of pitting.
3	Greater than 50%	Cluster of pits with some interconnection of pits.
3-	Greater than 50%	Isolated, scattered pits with little or no interconnection of pits.
2+	25% to 50%	Massive, concentrated, interconnected areas of pitting.
2	25% to 50%	Cluster of pits with some interconnection of pits.
2-	25% to 50%	Isolated, scattered pits with little or no interconnection of pits.
1+	Less than 25%	Massive, concentrated, interconnected areas of pitting.
1	Less than 25%	Cluster of pits with some interconnection of pits.
1-	Less than 25%	Isolated, scattered pits with little or no interconnection of pits.

¹⁵ The electromagnetic inspection device has been the primary tool used to detect metal loss in pipelines for more than 25 years. The correlation between the distortions recorded by the instrument and the actual metal loss was not as precise in the early pigs as those used today. As the equipment has been refined and operators have gained experience in interpreting the indications obtained using the magnetic-flux pig, the correlation has increased significantly. Consequently, verification excavations are no longer performed.

Before the accident, TETCO had conducted two internal inspections of Line 20 in 1986. On June 3, 1986, in accordance with TETCO's policy of setting the tool sensitivity for the thickest pipe wall in a line, the contractor set the tool for 0.844-inch thickness before pigging Line 20 from the Lambertville station to the Linden station. Because most pipe lengths in Line 20 had 0.675-inch-thick walls, TETCO officials recognized that anomaly indications detected by the tool would be exaggerated for 0.675-inch walls. At the end of the first inspection, TETCO determined that five of the 28 data channels were not functioning properly and graded the inspection run unacceptable.

On June 4, 1986, a TETCO contractor conducted another inspection run of Line 20, which TETCO determined was acceptable. TETCO selected for excavation verification an area that because of the size and spacing of multiple indications, met the criteria of a 1+ anomaly. On June 5, 1986, TETCO employees excavated and visually inspected a 45-foot length of pipe between MPs 3.02 and 3.03. They found no indications of corrosion or other damages to the pipe or its coating. TETCO records show the company technicians reported no pitting and the pipe was in excellent condition. They attributed the indications at the location to "pipe surface roughness." TETCO graded the log indications as shown in table 6 below.

Table 6. Results of 1986 Internal Inspection

Location (MP to MP)	Grade Indicated									Dents	Possible Dents	Unknown
	3+	3	3-	2+	2	2-	1+	1	1-			
0.00 to 6.10	0	0	0	0	1	3	33	28	53	0	0	0
6.10 to 12.81	0	0	0	0	1	3	44	23	39	0	0	0
12.87 to 18.96	0	0	0	0	0	2	0	2	135	0	2	0
18.96 to 19.85	0	0	0	0	0	1	0	0	14	0	1	0
19.85 to 23.70	0	0	0	0	0	0	0	2	104	0	2	0
23.70 to 24.20	0	0	0	0	0	0	0	0	11	0	0	0
24.20 to 29.60	0	0	0	0	0	4	0	0	105	0	3	0
29.60 to 35.00	0	0	0	0	0	1	0	3	103	0	5	1
35.00 to 39.70	0	0	0	0	0	4	0	1	79	0	9	2
39.70 to 40.20	0	0	0	0	0	0	0	0	3	0	2	1
Total	0	0	0	0	2	18	77	59	646	0	24	4

*A dent is a local depression in the pipe surface that produces a gross disturbance in the pipe curvature without reducing the wall thickness.
Note: MP area from 29.60 to 35.00 contains the rupture site.

After the accident, the TETCO South Plainfield Area Superintendent reviewed the log and identified seven indications for the pipe through the asphalt plant property. All indications were graded as minor anomalies, six as 1- and one as 1. He and an inspection tool contractor representative reexamined the log closely to determine whether indications of anomalies were near the rupture origin and found none. The Safety Board's review of the log identified no metal-loss anomalies in the area of the fracture origin or in the numerous large gouges on the pipe. Safety Board investigators noted two log indications on the pipe segment that included the origin gouge and one indication on the next pipe segment which they believed warranted additional investigation. On the origin gouge pipe segment, the two indications were 9.5 feet and 18 feet west of the east girth weld. The Board determined that the indication nearer the east girth weld represented an area of metal loss about 1 inch square and about 0.050 inch deep. The other indication represented a slightly smaller square area about 0.050 inch deep. The indication on the pipe segment east of the origin segment represented an isolated pit about 0.100 inch deep.

The area superintendent stated that after examining the various gouges in the origin pipe segment, he believes that had they been present at the time of the 1986 internal inspection, the smart pig would have detected and charted them. TETCO would then have identified the indications on the log as Grade 2 and excavated to inspect the pipe. He said the absence of any indication logged near the rupture origin convinces him the gouges were not present when Line 20 was pigged in 1986. The TETCO official's observations are supported by the Log Interpretation Department Supervisor of Tuboscope Pipeline Services, the manufacturer and operator of the pig used in the 1986 inspection. In a November 1, 1994, letter, the supervisor states that after comparing the marks and their locations on the pieces of pipe at the rupture site with the metal loss indications on the 1986 inspection log, she determined that some "small gouges" downstream of the rupture "correlated to the indications seen on the 1986 survey." She further states that gouges such as those found at the origin "would be expected to have significant signatures on the 1986 survey..." and that "no such signatures are visible."

TETCO officials said that Line 20 was scheduled and budgeted to be pigged in 1994 because of the line's class location, its criticality to service, and the many grade 1 indications detected in the 1986 internal inspection; however, the company did not have the opportunity to internally inspect the line before the March rupture.

Postaccident tests.--Between July 1 and 4, 1994, TETCO contracted for two different types of internal inspections of Line 20: one using a magnetic-flux pig and the other using an inertial geometry internal inspection tool, or inertial/caliper pig, which generates a full picture of the inside shape of a pipeline. The inertial/caliper pig enables operators to determine the deformation and slope of the pipeline and to measure changes in its position. Appendix D provides the contractors' analysis of the two inspections. The inertial/caliper pig has caliper sonars that scan the wall of the pipeline and yield the instrument-to-pipe translation and attitude. An inertial navigation system maintains the tool's position and attitude along its trajectory within the pipe. Other equipment measures the progress of the instrument through the pipeline, transmits a tracking signal, and electronically stores the data for retrieval and interpretation.

Correlation with 1986 inspection.--An anomaly indicated by the 1994 magnetic-flux inspection would be greater than the same anomaly indicated by the 1986 magnetic-flux inspec-

tion because the instrument was set for a wall thickness of 0.675-inch in 1994 and the setting in 1986 was at 0.844-inch. TETCO excavated eleven locations common to both the 1986 and the 1994 magnetic flux inspections and examined them using ultrasonic and magnetic particle tests (see table 7). After the accident, TETCO removed and reviewed 105 feet of pipe that was east of the rupture. Based on its review, TETCO determined the minor indications of mechanical surface damage on the pipe correspond with the minor damage indications on the 1986 internal inspection log.

Table 7. Correlation of 1986 and 1994 Internal Inspections
(MF indicates magnetic flux pig, IC indicates inertial/caliper pig.)

LOCATION (MP)	ANOMALY GRADE			INSPECTION FINDINGS (Defect position is based on looking downstream at a cross section of the pipe.)
	1986 MF	1994 MF	1994 IC*	
7.72	2	N/G	N/I	Internal defect, lamination. No cracks, dents, or corrosion found.
8.74	N/I	N/I	1.0	Plain dent at 6:00 (clock position) with no associated defect. No cracks found.
8.98	N/I	N/I	1.0	Plain dent at 6:30 with no associated defect. No cracks found.
9.10	N/G	A1	3.8	Dent with small cluster of gouges at 6:00. No cracks found. Maximum gouge depth 0.020 inch.
9.70	N/G	A1	2.3	Dent with minor corrosion pitting at 5:30. No cracks found. Maximum pitting depth of 0.020 inch.
10.29	N/G	A1	2.2	Dent with gouge at 5:00. No cracks found. Maximum gouge depth of 0.022 inch.
10.85	N/G	A1	2.1	Dent with two gouges at 5:30. No cracks found. Maximum gouge depth of 0.040 inch.
11.59	N/G	A1	2.1	Two dents with two gouges at 6:30. No cracks found. Maximum gouge depth of 0.050 inch.
28.33	N/I	N/I	1.9	Dent with minor corrosion at 6:00. No cracks found. Maximum pitting depth of 0.040 inch.
28.38	Dent?	A1	2.9	Dent with negligible corrosion at 6:00. No cracks found.
30.13	N/I	N/I	1.3	Dent at 6:00. No cracks found.
* Measurements shown in IC column represent a percent of the pipe diameter.				
Codes: 1986 grade 2 type anomaly indicates 30 to 40 percent metal loss. N/G - Indication is less than criteria for lowest grade anomaly. N/I - No indication of anomaly. A/I - Representative of meshes or dents in pipeline.				

Meteorological Information

Surface data obtained from a McIDAS (Man computer Interactive Data Access System) station box at the Newark Airport, about 15 nautical miles northeast of Edison, show that at 2350 EST on March 23, 1994, the skies were mostly cloudy, visibility was 15 miles, winds were calm, the temperature was 55°F, and the dewpoint was 39°F.

Survival Factors

A few weeks after the accident, the Safety Board mailed 150 questionnaires to a representative sample of residents in the 63-building Durham Woods Apartment complex. The survey asked residents to recount the events of the accident, to note whether they were aware of the pipeline, and to answer questions related to survival factors. The questionnaires completed and returned represented the occupants of 54 apartments. All respondents indicated they had no prior knowledge of the presence of the TETCO pipeline.

Damage Prevention

Federal Requirements.--Current Federal standards require each natural gas pipeline operator to have a written program to prevent damage to the pipeline by excavation activities. The program must include procedures for (1) identifying persons who routinely excavate near the pipeline; (2) notifying potential excavators and nearby residents how to identify the location of buried pipelines; (3) receiving and recording notifications of planned excavations; (4) communicating to excavators how a pipeline will be temporarily marked; (5) timely marking the pipe route through excavation areas; and (6) inspecting pipelines that the operator has reason to believe have been damaged by excavating activities.

One Call.--Federal damage prevention program requirements can be achieved either through programs developed by pipeline operators or through programs, such as "one-call" systems, that generally represent the combined efforts of several operators of buried facilities.¹⁶ Company officials stated that it is the TETCO policy to participate in all one-call systems covering areas in which its pipelines are located. Before this accident, the State of New Jersey did not require operators of underground facilities to join or excavators to notify a one-call system. TETCO has voluntarily been a member of the Garden State Underground Plant Location Service for years; however, it never received notice of any excavations within the asphalt plant property. In 1993, TETCO received about 14,000 notifications of planned excavations from the New Jersey notification center, and, as a result, the company installed temporary markers in about 1,000 areas to minimize the chance of excavation damage.

Before construction began on the Durham Woods complex, TETCO received plans for the project from the developer. The TETCO General Manager for Field Operations stated that the pipeline company's only comments or dealings with the developer concerned the potential impact on the pipeline, and TETCO did not have a position on the land development.

¹⁶ See 49 CFR 192.614.

Markers.--At the time the pipeline was constructed, the ASA code contained neither requirements nor recommendations for marking the location of buried pipelines. Current Federal standards¹⁷ require that line markers be placed and maintained as close as practical over transmission pipelines at each railroad and public road crossing and wherever a pipeline operator determines necessary to reduce the possibility of damage or interference. Federal regulations do not require line markers in class 3 and 4 locations where the operator either determines that placement of the marker is impractical or has a damage prevention program that is consistent with Federal requirements.¹⁸

When it built Line 20, TETCO installed concrete markers identifying the pipeline location on each side of all railroads, highways, and roads, and at other locations designated by its construction engineer. The company also installed aerial MP markers so that its patrolling pilots could provide location references with their reports. At either end of all casing pipes under roads and other crossings above the pipeline, TETCO installed vent pipes, which were painted orange and had warning labels imprinted with a toll-free telephone number for TETCO.

The markers installed near the asphalt plant property exceeded the minimum Federal safety standards. TETCO installed orange fiberglass markers (4 feet high by 4 inches wide by 1-inch thick) about 50 and 100 yards west of the plant entrance and east of the plant road-Talmadge Road intersection. The gas company installed an orange 4-inch-diameter casing vent pipe with a 180-degree elbow atop the 4-foot high pipe west of Talmadge Road and two orange casing vent pipes between the plant and the apartment complex. Each marker is imprinted with a notice advising that a TETCO natural gas pipeline is located in the area and providing 24-hour toll-free telephone numbers for Lambertville station and Houston Gas Control.

TETCO did not install pipeline markers within the asphalt plant complex or on the plant fence. The TETCO area superintendent stated that vertical markers could not be placed within the plant compound because of vehicular traffic and raw material stock piles continually being moved. He stated that in retrospect, TETCO could have installed a marker atop the earthen berm at the east property line.

Prior Excavation-caused Damage.--TETCO records show that since 1989, most damage to its pipeline system generally has been excavation-caused mechanical damage by others (see table 8). Some damages that necessitated repair include the following:

On May 11, 1979, while excavating to install an electric pole near MP 14 in Somerset County, New Jersey, an area electric and gas distribution company struck and gouged Line 20 with a mechanized auger.

On December 2, 1981, while building a 30-inch diameter extension of Line 20 at MP 44.34 in Richmond County, New York, the contractor dropped the track of a sideboom used for handling pipe onto Line 20 and damaged the somastic pipe coating.

¹⁷ See 49 CFR 192.707 (a) and (b).

¹⁸ See 49 CFR 192.614.

On May 5, 1992, while installing a water main in Somerset County, the contractor's backhoe struck Line 20 and made a 0.070-inch by 1/2-inch-long gouge in the pipe at MP 17.38.

Public Education and Liaison.--At the time the pipeline was constructed, the ASA Code contained neither requirements nor recommendations on educating the public on the hazards presented by pipelines. It also did not address communicating with community officials about the location of the pipeline or responding to emergencies related to the pipeline. Current Federal standards require that each operator establish a continuing education program to enable its customers, the public, the appropriate government organizations, and any persons engaged in excavation activities to recognize and report a gas pipeline emergency to the operator or appropriate public officials.¹⁹

Table 8. Prior damage to TETCO pipelines

Incident Type	Number	Percent of Total
Mechanical damage by others	27	41
Mechanical damage by TETCO	4	6
Material Defect	11	17
Corrosion	22	33
Natural Forces	2	3
Total	66	100

The TETCO *Operations and Maintenance Plan* requires that its personnel provide business cards and printed information concerning pipeline safety to persons living or working near the pipeline system. The handouts describe how to recognize a gas leak, advise what to do if a gas leak is suspected, and list indications or activities that should be reported to TETCO. The documents also include facts about natural gas, pipeline safety, the TETCO damage prevention program, and how the TETCO pipelines are marked, as well as a toll-free 24-hour telephone number and mailing address to which correspondence may be directed. The TETCO area superintendent and division manager are jointly responsible for documenting the distribution of pipeline safety information to the general public.

The TETCO South Plainfield Area Superintendent testified that before the 1994 accident, TETCO annually mailed flyers to landowners along the pipeline system. The flyers addressed TETCO's pipeline and excavation damage prevention program and advised how to recognize the pipeline location by TETCO markers, how to identify and report gas leaks, and how to report proposed excavations. Using the landowner information on file at the various county courthouses, TETCO compiled a computer data base, which the company uses to do annual mailings, generally in the fall. In rural locations, TETCO sends notices to all owners of property crossed by the pipeline; in urban areas, the company sends the notices to all owners of property which the pipeline crosses or to which it is adjacent.

The area superintendent further testified that when TETCO crews performing their normal duties meet landowners, the pipeline employees provide landowners with calendar books, which contain similar information contained in the flyers. TETCO also publishes notices in local newspapers to inform the general public about the pipeline and cautions to take when operating around it. TETCO officials stated that because of transiency, it would be an almost impossible

¹⁹ See 49 CFR 192.615 (d).

task for the company to contact all apartment tenants and building occupants along its 10,000-mile-long pipeline system. They said that TETCO believes the building owner or operator should be responsible for advising occupants about the pipeline and other necessary related information. TETCO suggested that landlords have building or apartment managers advise tenants about the pipeline at the time they lease their units.

The area superintendent acknowledged that TETCO had not reviewed, studied, or assessed the effectiveness of its public education program, but he knew that it was similar to programs used by other transmission pipeline operators to comply with Office of Pipeline Safety (OPS) requirements. He said that since the Edison accident, he has received some feedback from landowners acknowledging receipt of TETCO notifications and other documents.

Emergency Plans.--Federal standards require each pipeline operator to establish written procedures to minimize the hazard resulting from a gas pipeline emergency.²² The plan must, at a minimum, provide for (1) receiving, identifying, and classifying notices of events which require immediate response; (2) establishing and maintaining communications with police, fire and other public officials; (3) responding promptly and effectively to a notice of an emergency; (4) making available at the scene of an emergency needed personnel, equipment, and materials; (5) taking action first for protecting people and then for property; (6) providing emergency shut-down and pressure reduction of pipe sections necessary to minimize hazards to life or property; (7) making safe any actual or potential hazards to life or property; (8) notifying appropriate public officials of emergencies and coordinating with them both planned responses and actual responses during an emergency; (9) safely restoring any service outages; and (10) implementing an investigation of failures.

Chapter 12 of the TETCO *Operations & Maintenance Plan* establishes its policy for complying with each requirement of the Federal standards listed above. The TETCO *Emergency Response Manual* provides procedures on organizing and dispatching a response team to incidents. The manual details the specific responsibilities of each team member in managing the company's emergency, security, investigative, communication, and restoration activities.

The TETCO *South Fairfield Area Emergency Manual*, a company reference widely available to area supervisory, technical, station, and maintenance employees, contains an employee standby schedule, directions to all area valves, and listings of telephone numbers for TETCO employees both within the area and in Houston, contractors, and listings of medical services, police agencies, and fire agencies within each political jurisdiction throughout the area. The manual defines emergency incidents as facility failures that result in abnormal pressures, large volumes of uncontrolled escaping gas, fire or explosion, hazardous leaks, and endangerment of the system; certain gas delivery curtailments; natural disasters which make emergency provisions necessary, civil disturbances requiring special precautions, and national emergencies. It cautions employees to determine the effect on the entire pipeline system before operating any valves because improper operation can worsen a hazardous condition.

²² See 49 CFR 192.615.

The area manual describes actions employees are to take in response to emergencies, provides a TETCO chain of command, and lists records to be completed and maintained. The stated main objectives of actions taken during an emergency are:

- Maintain contact with TETCO management;
- Coordinate with local emergency officials and response teams;
- Prevent or contain the spread of damage;
- Render first aid, if required;
- Preserve the remains of the damaged equipment;
- If possible, maintain gas service to customers; and
- As soon as possible, perform emergency repairs to damaged equipment.

To accomplish those objectives, the area manual provides instructions on notifications to other TETCO personnel, dispatching TETCO response employees, responding to emergencies, actions of first TETCO onscene person including evacuation of the public and blockading of hazardous areas, operation of valves, coordination with emergency teams, and responding to media contacts. It provides more detailed instruction on actions to take for specific emergencies, such as gas leaks, civil disturbances, and natural disasters. Among the many immediate actions for first responders, the manual lists eliminating or controlling the escape of gas by closing valves, blowing down piping, or other means.

The area manual also addresses emergency preparedness actions, including employee knowledge of the manual and response actions, employee training, maintenance of emergency equipment and materials, and maintenance of pipeline maps. The manual assigns each area superintendent and/or division manager the responsibility of periodically communicating with public officials in jurisdictions along the pipeline system to advise them about TETCO emergency procedures and the company's intent to coordinate with them during emergencies.

TETCO conducts annual emergency response association briefings and an annual general meeting to which it invites all communities crossed by its pipelines. The South Plainfield Area Superintendent held two such meetings in 1993 and one in 1992 at which he made presentations on TETCO's general operations and then detailed presentations on the design of the pipeline, operations and maintenance practices, and TETCO emergency procedures. TETCO routinely shows films of recent pipeline accidents and their effects at the meetings. As a standard invitation at those meetings, TETCO offers to go into any community to present a site-specific or community-specific presentation to provide greater detail as to what might occur within that community. TETCO provides a map showing the location of its pipelines in New Jersey at those meetings. One representative of Edison Township attended one of the 1993 meetings.

The Edison Fire Chief stated that because of the many area pipelines, his department receives too many invitations for his staff to attend all the training sessions offered by the various pipeline operators. He believes the information provided at a training session conducted by one company is reasonably applicable to other pipeline operations and that his personnel are adequately knowledgeable about actions to take when dealing with pipelines emergencies.

TETCO annually conducts in-house emergency drills to determine their employees' know-

ledge of emergency procedures and how they might react to specific emergency conditions. TETCO has not participated in similar drills or exercises with any community emergency response agencies in the area of the pipeline nor has any community response agency invited TETCO to do so.

Metallurgical Examination

A Safety Board metallurgist, by examining characteristics exhibiting fracture directions, determined that the fracture originated in the pipe fragment still attached to the eastern pipeline segment. Investigators cut pipe specimens containing both halves of the fracture origin, several other sections of the pipe containing damage on the outside surface, and a section of pipe unaffected by the fire for laboratory examination. The origin area was in a gouge located at the 1:30 o'clock position looking downstream; about 16 inches down from the top of the pipe. The gouge had reduced the wall thickness to 0.500 inches, a reduction of 26 percent. While most of the fracture in the area of the origin was along the longitudinal pipe direction, a small portion of the fracture at the bottom of the gouge followed the direction of the gouge, which was oriented about 30 degrees from the longitudinal direction of the pipe.

Examination using a scanning electron microscope (SEM) showed that all microscopic fracture features in the origin area had been obliterated by oxidation resulting from the fire. In addition, the pipe material microstructure was depleted of carbon (decarburized) in regions adjacent to the fracture surface and the exterior and the interior surfaces of the pipe and, that carbides in the pearlite colonies were spheroidized.²³ Both surface decarburization and spheroidization of carbides are indicative of a prolonged exposure to elevated temperatures.

Investigators found another pipe fragment containing a deep gouge that was not subjected to heat damage. Reconstruction showed that this fragment was from an area just west of the primary fracture origin area. The gouge was at the 11:30 o'clock position and was oriented about 60 degrees to the pipe's axial direction. The remaining wall at the bottom of the gouge was 0.441 inch thick, which represented a 35 percent reduction in pipe wall thickness. SEM examination showed that the fracture features on the surface intersected by the gouge were predominantly cleavage, which is a brittle fracture mechanism. Further examination revealed that the bottom of the gouge contained a crack. The crack had an irregular transgranular path that had propagated primarily perpendicular to the pipe's exterior surface and was filled with corrosion deposits. Upon opening the crack and conducting an SEM examination of it, the Safety Board determined it showed no evidence of progressive fracturing.

Examination within the gouge unaffected by fire disclosed several areas of transferred metal on the gouge wall. X-ray Energy Dispersive Spectroscopy (EDS) of the pipe metal generated characteristic peaks for carbon, manganese, and iron consistent with the pipe material specification. EDS analysis of the transferred material generated a spectrum that contained peaks for the same elements, as well as additional peaks for silicon and chromium. The microstructure of the transferred metal differed from the microstructure of the pipe material. The material of the

²³ In the normal microstructure of a low carbon steel, carbides exist in the form of platelets.

pipe surrounding the particles of transferred metal was heavily deformed and cracked.

Microhardness measurements of the pipe material gave an average value of 213 DPH²⁴, which is equivalent to a Rockwell hardness of 96 HRB (less than 20 HRC).²⁵ The average microhardness measured within the transferred material was 441 DPH or 45 HRC.

The Safety Board determined the chemical composition and mechanical properties of the pipe material on a pipe section containing no visible evidence of heat damage. Tests confirmed the chemical and tensile properties of the metal met the requirements of API Standard 5LX for Grade X52 steel. The pipe material's brittle-to-ductile transition temperature, as determined by Charpy V-notch tests, averaged 172°F.²⁶ At the time of rupture, the operating temperature of the pipe was about 29°F.

Asphalt Plant History

Before the construction of Line 20, an asphalt plant had operated since 1947 on the 8-acre land tract where the rupture occurred. County records and company files show the property changed ownership several times after TETCO designed and built Line 20. TETCO's easement was incorporated in the deed at each conveyance. A provision of the easement prohibited the landowner from changing the grade over the pipe. The Board obtained aerial survey photographs from which investigators could chronicle changes to the plant property and land surrounding the 8-acre tract between 1955 and 1994. (For examples, see figures 7a, 7b, 7c, and 7d.)

At the time Edison Asphalt Corporation purchased the 8-acre property on July 20, 1960, one pond was located in the northeast area of the plant property. An employee who has worked at the asphalt plant since 1960, except for a 2-month period between January and March, 1984, recalls seeing the TETCO pipeline being constructed. He says that between 1961 and 1965, the asphalt company used backhoes to excavate and construct two additional ponds on the property, one to serve as a water source for the no. 2 plant operations and the other to serve as a repository for sediment from the plant. In addition, the asphalt company had underground pipes installed from the original pond to the no. 1 plant and from the new water pond to the no. 2 plant. He says about every 6 months the company cleaned the sediment pond using a crane having a clamshell-type excavation bucket with no teeth on its digging edge.

Edison Asphalt subsequently sold the property to Halecrest Construction Corporation (Halecrest). On March 31, 1978, Halecrest conveyed the property to Haskell Excavating Corporation (Haskell). In a separate and concurrent agreement, Haskell granted Halecrest a vehicular access easement in the northwest side of the property, conditional on compliance with all

²⁴ Hardness was measured at 200 gram load using a diamond pyramid indenter.

²⁵ 100 HRB is equivalent to 20 HRC.

²⁶ The Safety Board determined the brittle to ductile transition temperature was the temperature at which Charpy V-notch specimens exhibited 85 percent area of shear fracture. This corresponds to an abrupt change from ductile to brittle fracture behavior in full-scale material.

rights granted to TETCO in 1960. On February 14, 1984, Haskell sold the 8-acre asphalt plant tract with all easements to Quality Materials, Inc., a subsidiary of Sta-Seal, which is owned by Trap Rock Industries. The Haskell owner recalls the property consisted of two or three asphalt plants, a silo, and two ponds.

The employee, who has worked at the plant since 1960, said that before the property was sold in 1984, the plant was modified and the ponds were no longer needed. He describes the plant property in January 1984 as being a mess with isolated "pockets of junk," such as scrap metal, old machinery parts, and so forth, throughout the plant. He says that his Haskell supervisor instructed him to fill in the ponds using the scattered junk within the plant property.

According to an employee who worked on the project, he and co-worker, acting on instructions from their supervisor, gathered waste materials that were stored south of the plant, and placed the materials in the ponds beginning at the south edge, shoving them in using a bulldozer, and then covering them over with soil. They continued the process for about a month. Working in a south to north direction, they drove the bulldozer back and forth, dumping and covering debris until they had filled the ponds. He says the debris that they dumped into the ponds included trash in drums, structural steel, and parts of the old plant. A March 26, 1984, aerial photograph shows no evidence of any ponds.

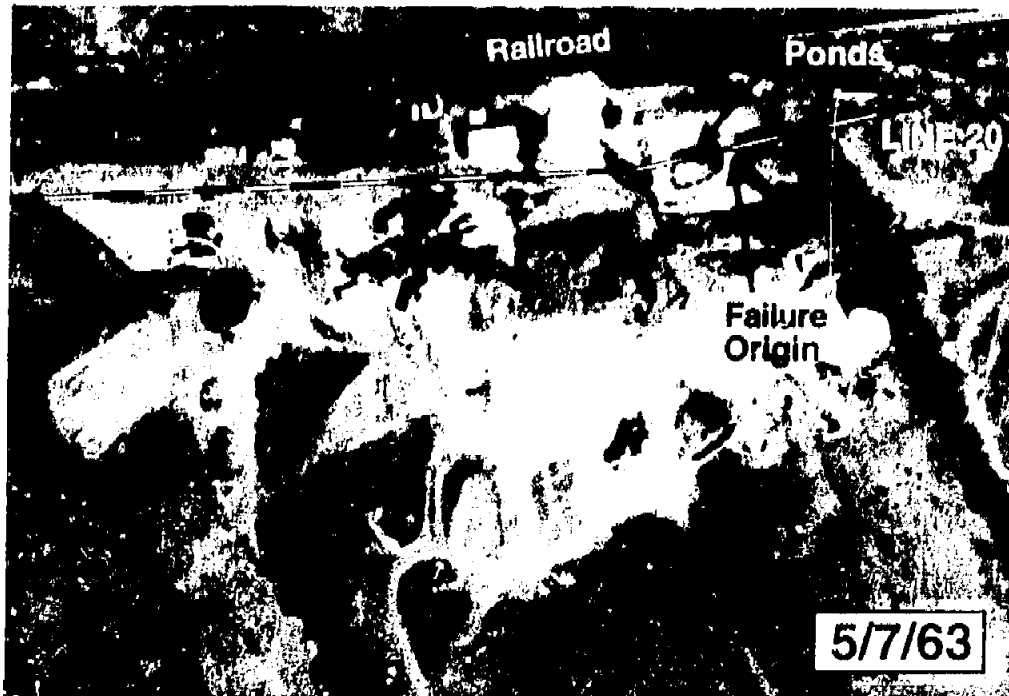
Another plant employee says that he never observed any below-grade digging after he began work for Quality in 1987. He says that the only earth-moving equipment at the plant were a front-end loader and a D7 bulldozer, both of which had straight-cutting edges. He says that he was never aware that a gas transmission pipeline crossed the property.

After the 1994 accident, crews excavated and recovered numerous pieces of material above and adjacent to the pipeline, most of which was identified as debris that was dumped in the ponds by the employees who filled the ponds in 1984. Some recovered surface debris was blown from the hole excavated by the rupture. Interviews with current and previous plant employees show that some who had observed the pipeline being built, TETCO employees walking the line, and/or TETCO markers were aware that a pipeline was within the plant property. None of the asphalt plant employees recalled being trained or familiarized about the pipeline or precautions to take when working near it from their current or previous plant owners.

Regulatory Oversight

Federal Energy Regulatory Commission (FERC).--Under the Natural Gas Act, the U.S. Department of Energy's FERC has three principle responsibilities relative to interstate natural gas pipelines:

- o Determining whether the facilities are in the public interest;
- o Ensuring just and reasonable rates; and
- o Approving the siting of a pipeline.



Jul 20, 1960 - Edison Asphalt Corporation purchases the 8-acre property through which TETCO has easement rights for its pipeline.

Apr 20, 1961 - The land near railroad is used for farming (figure 5 on page 10 of this report).

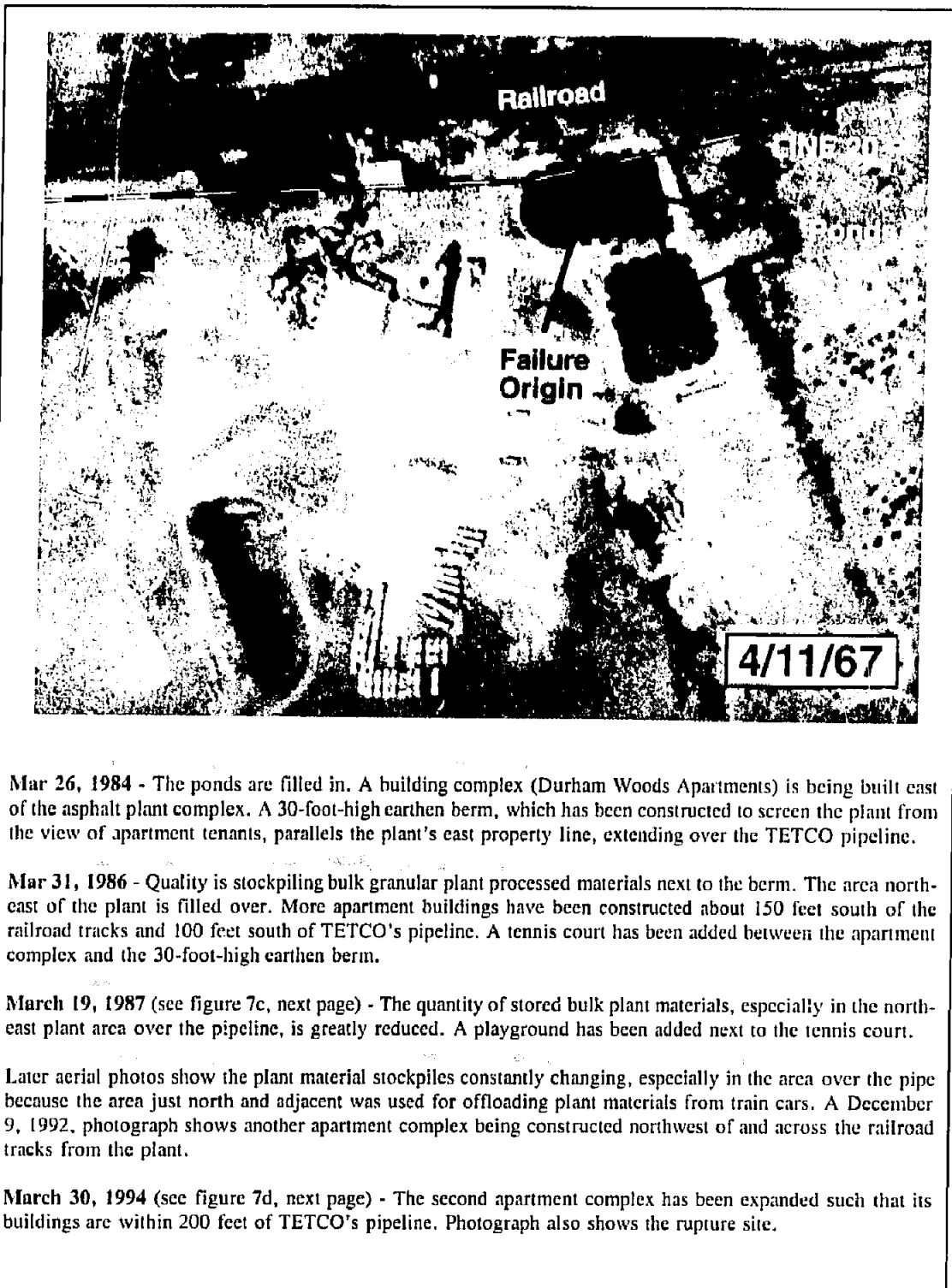
May 7, 1963 (shown above) - The settling pond at the northeast corner is reshaped, resulting in the pond being nearer, if not over, the pipeline. A second smaller pond, west of the original pond, crosses over the pipeline.

Apr 11, 1967 (see figure 7b on next page) - The two ponds have been merged so that the northern portion of the larger pond crosses over the pipeline.

Aerial photos between 1967 and 1979 show the merged ponds filled with sediment and the north side of the merged ponds often varied, likely a result of the ponds being cleaned using the dragline bucket to remove silt. A March 23, 1969, photo shows a crane or similar equipment on the north edge of the merged ponds. The south third of the pond is filled, likely with plant sediment. A February 23, 1970, photo shows a crane on the north edge of the merged ponds.

Mar 26, 1976 - A crane is near the edge of the merged ponds. About one-third of the pond is filled with sediment except areas near the crane. The route of a newly excavated ditch crosses TETCO's pipeline west of the 1994 rupture origin. The dirt pattern resembles that made by a backhoe and a piece of equipment resembling a backhoe is near the ditch.

Figure 7a. Chronicle of plant property changes.



Mar 26, 1984 - The ponds are filled in. A building complex (Durham Woods Apartments) is being built east of the asphalt plant complex. A 30-foot-high earthen berm, which has been constructed to screen the plant from the view of apartment tenants, parallels the plant's east property line, extending over the TETCO pipeline.

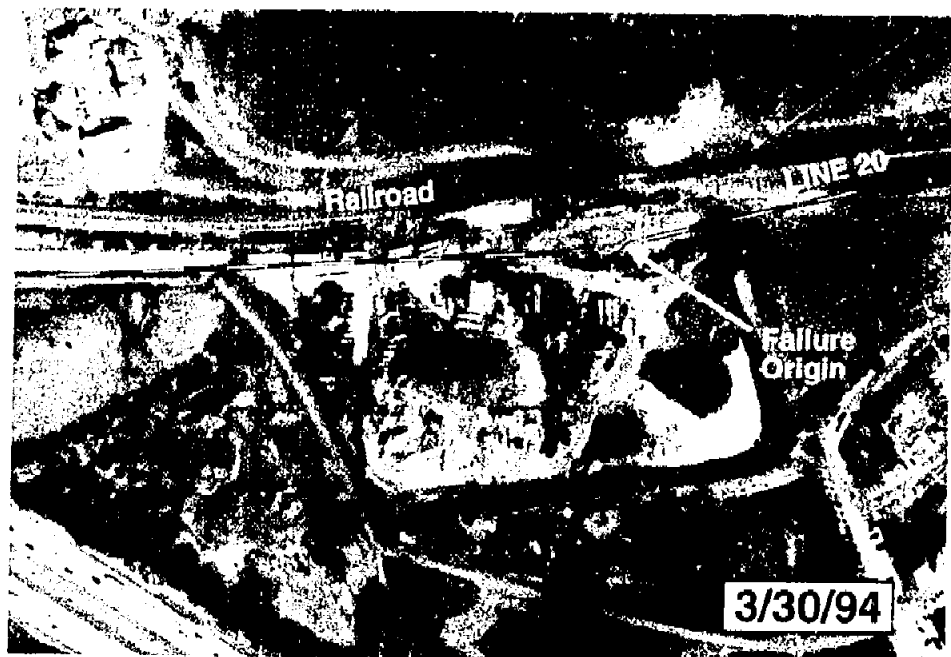
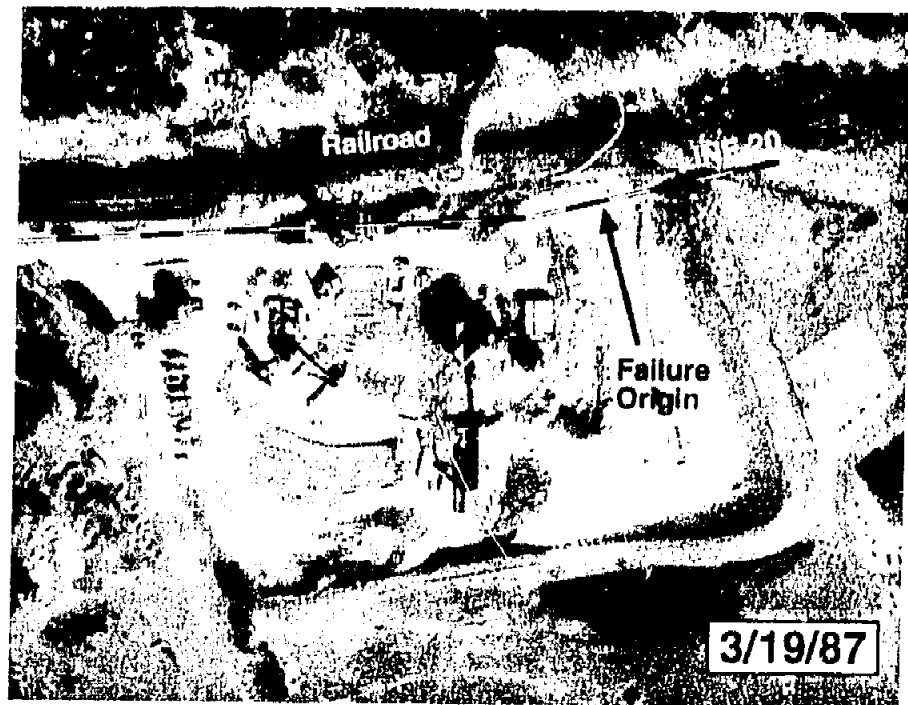
Mar 31, 1986 - Quality is stockpiling bulk granular plant processed materials next to the berm. The area north-east of the plant is filled over. More apartment buildings have been constructed about 150 feet south of the railroad tracks and 100 feet south of TETCO's pipeline. A tennis court has been added between the apartment complex and the 30-foot-high earthen berm.

March 19, 1987 (see figure 7c, next page) - The quantity of stored bulk plant materials, especially in the north-east plant area over the pipeline, is greatly reduced. A playground has been added next to the tennis court.

Later aerial photos show the plant material stockpiles constantly changing, especially in the area over the pipe because the area just north and adjacent was used for offloading plant materials from train cars. A December 9, 1992, photograph shows another apartment complex being constructed northwest of and across the railroad tracks from the plant.

March 30, 1994 (see figure 7d, next page) - The second apartment complex has been expanded such that its buildings are within 200 feet of TETCO's pipeline. Photograph also shows the rupture site.

Figure 7b. Chronicle of plant property changes.



Figures 7c and 7d. Chronicle of plant property changes.

Although the FERC is responsible for ensuring the safety of pipelines that it approves, the RSPA Office of Pipeline Safety (OPS) has the primary responsibility for pipeline safety. Consequently, FERC requires that all pipelines subject to its jurisdiction comply with OPS safety standards. In testimony before the U.S. Senate Committee on Energy and Natural Resources on April 19, 1994, the FERC Chairman described the competing concerns of the FERC when it reviews proposals for pipelines through urban areas. She listed several statutes that the FERC must consider during its review process, including the National Environmental Policy Act, the Endangered Species Act, the National Historic Preservation Act, the Coastal Zone Management Act, the Clean Water Act, the Clean Air Act, and others. She stated that a selected route ultimately reflected a "balancing of all the competing concerns" and that the primary concern in the decision-making process "is to minimize the impact on people living along the route." She stressed:

Above all, the Natural Gas Act requires us to analyze whether a project is in the public interest. This means we focus on local land-use issues. We try to avoid or minimize the impact on residences, schools, hospitals, and businesses and try to meet local land-use concerns.... In congested areas in particular we examine ways to minimize impacts on residential properties.... We actively identify and pursue alternative routes. As a general matter, the Commission prefers that pipelines use routes that affect the least number of people. However, large areas of the United States, particularly in the Northeast, are increasingly urban in character. Pipelines are built in response to the need for natural gas, which is at its greatest in heavily populated, urban areas. It is not always possible to avoid siting pipelines in congested areas and still get gas to consumers.

The FERC Chairman further stressed that Federal authorities were not responsible for land management decisions that might impact pipeline facilities after they are constructed. She stated:

State and local authorities share the responsibility for approving and permitting the construction of businesses and residences and any public use of land adjacent to pipeline rights-of-ways.... Meeting the needs for pipeline transportation and safety and local development priorities is not simple. It requires ongoing coordination and planning.

Research and Special Programs Administration (RSPA).--The Natural Gas Pipeline Safety Act of 1968, as amended, provides exclusive authority to RSPA on establishing and administering safety standards for interstate natural gas transmission pipelines. The OPS, which administers the pipeline safety program, must oversee a transportation system of more than 1.7 million miles of pipe transporting natural gas to about 55 million residential and commercial customers. Federal safety standards applicable to both interstate and intrastate natural gas pipelines are established in Title 49 CFR Parts 191, 192, and 199. The OPS considers its regulations minimum performance standards.

RSPA's Inspection of TETCO.--Before the accident, RSPA last inspected and evaluated TETCO for compliance with the applicable requirements in Title 49 CFR Parts 191 and 192 between July 8 and October 10, 1992. RSPA found no deficiencies as a result of its inspection.

Hazardous Facility Order.--Following the Edison accident, RSPA issued Hazardous Facility Order CPF No. 14101-H, on March 26, 1994, advising TETCO that it (RSPA) believed resuming Line 20 operations at the line's previous operating pressure would pose a hazard to life, property, and the environment. Citing the location of the pipeline in a heavily populated area and the gravity of the failure, RSPA required that TETCO accomplish several actions before it would authorize reopening the line. (See figure 8.)

On March 28, 1994, RSPA amended its Order to require that TETCO continue exposing the pipeline in the rupture area at least one pipe length beyond any dent or gouge found. RSPA coordinated with Edison Township and the New Jersey Board of Public Utilities (N. J. State Board)²⁷ to apprise them of proposed actions and seek their comments.

TETCO removed and replaced about 220 feet of the pipeline within the asphalt plant property (90 feet of pipe west of the rupture contained dents and gouges). The company successfully pressure tested to 1,975 psig (101 percent SMYS) about 6,200 feet of pipeline, including the pipe through the asphalt plant property. The adequacy of all girth welds on the new pipe were confirmed using X-ray inspection. On April 12, 1994, RSPA agreed to allow TETCO to resume operating Line 20 at the restricted pressure of 690 psig. To provide Edison Township the opportunity to inform residents about resumption of operations, TETCO delayed returning Line 20 to service until 6 p.m. the following day.

On April 27, 1994, TETCO submitted a proposal to conduct an instrumented internal inspection of Line 20. On May 5, 1994, RSPA and TETCO representatives met, discussed the plan, and agreed to revisions. TETCO and RSPA continued making revisions until June 1, 1994, when RSPA advised TETCO that although it (RSPA) had not approved the inspection plan, it was confident that if TETCO followed the inspection procedures proposed in the plan, the operator "would identify injurious gouges, dents, and corrosion that possibly could be detri-

Restrict the maximum operating pressure of Line 20 to 690 psig at station 26.

If the Safety Board does not conduct metallurgical analysis of the ruptured pipe segment, contract an independent laboratory to determine the pipe and weld material properties with emphasis on material toughness, the existence and extent of any mechanical damage, and whether corrosion or any other factors caused or contributed to failure.

Before returning the pipeline to service, expose an area of pipe at least one pipe length in each direction of the heat-affected area to determine whether any dents or gouges are on the pipeline.

Before returning the pipeline to service, metallurgically test and repair or remove any dents or gouges.

Within 10 days of resuming operation, submit a plan to RSPA for internal instrumented inspection of Line 20 to identify dents, gouges, and other anomalies that could lead to pipe failure and repair those anomalies.

Inspect the pipeline using an instrumented internal inspection device and repair anomalies.

Maintain the required lower pressure level until RSPA determines all corrective actions required by the Order have been met.

Figure 8. RSPA-Required actions of TETCO.

²⁷ Formerly the New Jersey Board of Regulatory Commissioners, the New Jersey Board of Public Utilities is certified by the DOT to administer the safety program over interstate natural gas pipelines in New Jersey.

mental to public safety." RSPA stated that an inspection such as the one proposed "would unquestionably have identified the mechanical damage found on Line 20 in the asphalt plant yard." Before making its final decision on the plan, RSPA provided the Edison Township and the N. J. State Board the opportunity to review the plan and provide comments. On June 17, 1994, both Edison Township and the N. J. State Board concurred in the plan and RSPA advised TETCO that the inspection plan was acceptable. (Figure 9 paraphrases the terms of the approved plan.)

TETCO conducted the internal inspections (See earlier section for inspection results) and advised RSPA that it planned to excavate 10 areas to perform further evaluations and tests. RSPA questioned whether wet fluorescent magnetic particle testing would detect cracks such those that the Safety Board identified in its metallurgical examination of the fractured pipe sections. Both TETCO and its contract testing company assured RSPA that such cracks would be detected.

On September 9, 1994, after citing the inspection results, the repairs made, and its obligation under the FERC certificate to provide natural gas via Line 20 to local gas distribution companies and industries, TETCO petitioned RSPA to rescind the Order and allow it to resume operating Line 20 at the previous MAOP of 975 psig. TETCO also provided a plan in which it would increase the pressure in Line 20 in two equal steps over a 2-day period, conducting leakage surveys after each pressure increase beginning on September 29, 1994. RSPA provided copies of the TETCO request to the Edison Township and the N. J. State Board for comment.

On September 22, 1994, based on comments from Edison Township, RSPA modified the plan to require that TETCO increase the pressure in three equal steps over 3 days with leakage surveys after each step. On September 30, 1994, TETCO completed repressurizing Line 20 as required by the amended plan. On October 3, 1994, TETCO requested rescindment of the Order, which RSPA did on October 12, 1994.

RSPA review of New Jersey's Damage Prevention Program.--Before the accident, RSPA advised the N.J. State Board on April 20, 1993, that the New Jersey underground damage prevention program might not be consistent with all provisions of 40 CFR Title 49, Part 198. State

Inspect Line 20 with both a magnetic flux and an inertial geometry internal inspection instrument.

Inspect the following:

Clusters of dents:

Dents within a girth weld or longitudinal weld seam; and

Dents in the bottom segment of the pipe (from 5 to 7 o'clock position) that are less than 2 percent of the nominal pipe diameter and that are 6 inches or longer along the longitudinal pipe axis. In areas where underground facilities have been constructed across the pipeline, such dents that are 2.5 inches or longer.

Evaluate the following:

All indications of plain dents in the pipe;

All indications of gouges and of corrosion;

All excavated dents using ultrasonic and wet fluorescent magnetic particle inspections;

All plain dents in the top segment of the pipe (from 7 to 5 o'clock position) that are less than 2 percent of the nominal pipe diameter and that are 4 inches or longer along the longitudinal pipe axis. Where underground facilities have been constructed across the pipeline, inspect such dents that are 2.5 inches or longer.

Repair or replace pipe that contains dents, gouges, or corrosion that might threaten the continued safe operation of the pipeline.

Figure 9. Inspection plan requirements.

statute N.J.S.A. 2C:17-4 prohibited persons from discharging explosives and excavating in streets, public places, or private property before determining whether gas or liquid pipelines were within 200 feet of the proposed activities. If so, the person proposing the blasting or excavation was required to notify the pipeline operator either by written notice or by calling the Garden State Underground Plant Location Service (New Jersey's one-call notification system). However, the statute exempted activities associated with replacing electric or communication service poles and their appurtenances. It also exempted work performed by or on behalf of the State transportation department, by persons using nonpowered hand tools on private property to a depth of 18 inches or less, by persons excavating during an emergency involving danger of death or serious personal injury, and by public utilities having a written agreement with pipeline operators. A person violating any provision is guilty of a "disorderly person offense."

The N.J. State Board responded on May 18, 1993, that because the notification provisions of the New Jersey Underground Facility Protection Act were enforced through State statute, the program could only be altered through State legislative amendment. The N.J. State Board referred the matter to its legal counsel, the New Jersey Attorney General's Office, for a legal opinion, and assured RSPA that if the State statute was not in full compliance with the CFR, it would take any action within its power to bring the program into compliance.

In 1994, RSPA performed two evaluation of New Jersey's pipeline safety actions for compliance with the certification requirements of Section 5(a) of the Natural Gas Pipeline Safety Act of 1968. In a June 10, 1994, letter advising the N.J. State Board of its findings, RSPA stated that it supported the N.J. State Board's pledge to strengthen the New Jersey Underground Facility Protection Act. RSPA advised that it had reviewed the draft legislation prepared by the N.J. State Board, found it to be consistent with the requirements of Part 198, and offered to assist the N. J. State Board secure passage of the legislation.

In a July 27, 1994, letter to RSPA, the N. J. State Board stated that strengthening of New Jersey's underground damage prevention program had been one of its major objectives the preceding year. The State Assembly had already approved draft legislation, which the Senate was expected to consider in September, 1994. Following the Edison rupture and fire, the Governor of New Jersey signed into law on October 18, 1994, a new excavation damage prevention act, which includes, in part, the provisions shown in figure 10:

Postaccident study.--As a result of the Edison accident, RSPA contracted the New Jersey Institute of Technology (NJIT) in August 1994 to perform a study on methods for reducing the risks and enhancing pipeline safety and environmental protection with respect to the siting and proximity of pipelines. RSPA noted that the existing population-based requirements, which were considered adequate for assessing risk in the past, proved to be inadequate in the Edison, New Jersey accident. RSPA acknowledged the need to reevaluate pipeline safety regulations in 49 CFR Parts 192 and 195 as they relate to the proximity of pipelines to populated and environmentally sensitive areas. The contract requires that the institute:

All operators of underground facilities must:

- participate in a One-Call Damage Prevention System and mark the location of their facilities when in an area described by a notice; and
- [operators of interstate pipelines] file a map depicting the pipeline route with each municipal clerk in the State, with the New Jersey Department of Environmental Protection, and with the State Board;

All excavators must:

- notify the One-Call Damage Prevention System before excavation or demolition;
- not operate mechanized equipment within 2 horizontal feet of the outside wall of any buried, marked facility until its location is confirmed by hand digging to expose the facility; and
- comply with the provisions of the act or be subject to being charged and prosecuted with violating a "crime of the third degree."

The New Jersey Board of Public Utilities is designated to operate and provide oversight to the One-Call Damage Prevention System ...(and has) authority to:

- provide a waiver to operators from facility requirements when no threat to public safety exists or a buried facility cannot be damaged;
- seek Superior Court injunction or other relief for any violation of the act or regulations made under the act; and
- impose administratively on persons whose violations affect natural gas or hazardous liquid pipelines monetary penalties up to \$25,000 for each violation for each day the violation continues, except the total penalty may not exceed \$500,000.

The one-call notification system shall be a statewide, 24-hour, 7-day-a-week center that:

- receives and records notices of intent to excavate;
- assigns a confirmation number to each notice and maintains a register on the notice;
- transmits the notice information to appropriate operators;
- provides excavators with the names of operators to be notified; and
- provides a fee schedule for using the one-call system.

Figure 10. Excerpts from New Jersey Public Law 1994, Chapter 118.

Develop a framework in safety and environmental pipeline areas to be compared with the Federal requirements, with industry practice, and with foreign regulations in the areas of rehabilitation and retrofitting practices and land use and siting requirements.

Assemble two groups consisting of no more than seven members to provide technical assistance on factual matters and to give the institute feedback needed in completing the analytical requirements of the contract. One group shall be composed of individuals having pipeline engineering and technical expertise and the other of representatives from the environmental community and representatives having expertise in New Jersey land use and zoning matters.

Study the probability of failures that can occur on gas transmission and hazardous liquid pipelines and identify the factors that cause pipeline failures. The institute

shall consider failures that might occur anywhere along the pipeline corridor, but shall concentrate on failures that occur at high risk areas and environmentally sensitive areas, such as urban areas and water bodies used for human consumption.

RSPA listed factors affecting accidents that the institute should consider in its study, such as pipe pressure, patrolling, markers, pipe materials, and land-use policies. The contract does not explicitly exclude or include consideration of factors identified in the Edison investigation, such as the type of building construction adjacent to pipeline rights-of-way and the effect of radiant heat and/or shock waves resulting from pipeline accidents. The contract also contains provisions for further work should RSPA determine that it is needed.

Inspection of New Jersey Interstate Pipelines.--After the accident, RSPA formed an inspection task force comprising representatives of its OPS, the DOT's Transportation Safety Institute, and the N. J. Safety Board to investigate the safety standards of the six interstate gas transmission pipelines in New Jersey. The task force reviewed safety inspection records, and examined the operations, maintenance, and emergency procedures to assess operator compliance with applicable Federal pipeline safety regulations. The task force paid specific attention to each operator's accident statistics, types of valves used, valve operators installed and back-up systems available, internal pipeline inspection procedures, hydrostatic testing programs, corrosion control systems, right-of-way patrols performed, and provision for public education. During the 2 months after the Edison accident, the task force inspected about 968 miles of interstate gas transmission pipelines. RSPA is currently evaluating the inspections findings.

ANALYSIS

Metallurgical analysis of the Line 20 pipe fragments after the accident show the scrapes were made by nonexcavation activities and the gouges were made by mechanized excavation equipment. The Safety Board was able to determine that the nonexcavation scrapes were made in 1984 when plant personnel filled the sediment pond with dirt and plant debris. The Board was able to determine that the gouges were made after June 4, 1986, but was unable to determine when they were made or who caused them. In the following analysis, the Board lists the factors and conditions it was able to exclude, identifies improvements needed for pipelines, especially in urban areas, and discusses the need for improved pipe metal properties to limit pipeline failures and/or mitigate their consequences.

Exclusions

The findings from TETCO's 1986 magnetic flux internal inspection, which the company verified by excavating, inspecting, and testing various points along the pipeline, indicate the rupture origin gouge and other major gouges found on the pipe after the accident were not present when the line was pigged in 1986. The indications on the 1986 internal inspection log were of metal losses insufficient to have caused pipe failure. Witnesses recall and aerial photographs show heavy equipment, including a bulldozer and dredging equipment, being operated in the area of the sediment pond over the pipeline before TETCO's 1986 internal inspection of Line 20. The metal loss indications on the 1986 log corresponds with minor scrape marks on the pipe within the pond. The Safety Board concludes that the indications detected in the 1986 internal inspection were the deeper portions of scrapes made when plant employees bulldozed plant debris and dirt into the sediment pond and when dredging equipment contacted the pipe during sediment removal operations. The Board further concludes that the gouge that ultimately resulted in pipe failure was caused by excavation activity sometime after June 4, 1986.

The gouges on the pipe were not the result of recent excavation damage. The Safety Board examined the microstructure of the pipe material underlying the non-rupture origin crack and found it was heavily deformed and contained a crack covered with corrosion deposits. The large build-up of corrosion deposits in the non-origin crack indicates that the crack was present in the pipe metal for some time, likely from when the pipe was gouged.

The gouge damage alone was not sufficient to cause the steel pipe to fail under operating pressure when it was injured. Also, subsequent operation of the damaged pipe even at maximum pressure did not cause the rupture. During the 2 years before the rupture, TETCO frequently operated Line 20 at maximum pressure without failure.

Pipeline employee performance was not a factor in the pipe being damaged or in the damage not being detected by TETCO. From interviews and observations, the Safety Board determined that the survey pilot can easily observe activities and vegetation along the pipeline route without experiencing any workload problems. From interviews with the Houston controllers, the Lambertville operators, and other TETCO employees, the Safety Board established that they were adequately trained and experienced and correctly performed assigned tasks consistent with

TETCO procedures. However, the pipeline company procedures did not stress that its employees pay particular attention to activities within industrial complexes that might endanger its pipelines.

The Failure

The rupture initiated at a gouge that significantly reduced the pipe wall thickness. Although the initiation gouge was not the deepest, it was aligned closer to the longitudinal direction of the pipe than any other significant gouge. The failure initiation location was therefore more susceptible to overstress from hoop (circumferential) stresses caused by pressurization. In addition, stresses associated with gouges closer to the top of the pipe would probably be reduced as a result of overburden.²⁸

As part of its analysis of the gouge defect, the Safety Board calculated the estimated stresses to the pipe under various conditions. Examination of TETCO records show that while the company was operating Line 20 at less than its maximum pressure on the date of the accident, it frequently had operated Line 20 at maximum pressure, or 975 psig, during the 2 years before the accident. At the maximum operating pressure of 975 psig, the hoop stress in the undamaged portions of the pipe would be 26,000 psi, 50 percent of the material SMYS. At the rupture initiation area, the wall thickness was reduced from 0.675 inch to about 0.5 inch. Ignoring stress concentrations associated with the gouge or crack at the gouge bottom, calculations show the pipe wall stress at the initiation area would have increased to about 35,100 psi, about 67 percent of SMYS. Stress concentration effects would increase the actual stress at the gouge bottom or at the tip of a crack associated with the gouge to levels that could approach 100 percent of SMYS. At such high stress levels, relatively minor fluctuations in pressure can cause a crack to grow. Pressure charts for the pipeline show pressure differentials of 200 psi to 350 psi, corresponding to changes in the hoop stresses in the range of 7,200 psi to 12,600 psi (assuming a 0.5 inch wall thickness). These fluctuating stresses likely were sufficient to cause any cracking associated with the gouge to grow, for example through metal fatigue, to a critical size at the time of the rupture.

The Board attempted to determine the cause of the gouges in the pipeline by analyzing metal transferred to the surface of a gouge undamaged by fire. The chemical composition, hardness, and microstructure of the transferred metal were different than the pipeline material and were typical of the steel type used in the teeth of mechanized excavation equipment.

Adequacy of Safety Measures in Urban Areas

The Edison, New Jersey, pipeline accident again demonstrates the need to improve pipeline safety measures, particularly in urban communities. As a result of its investigation, the Safety Board identified problems in a number of issue areas, including steel toughness properties (see separate section later in this analysis), pipeline marking, surveillance procedures, damage

²⁸ Overburden would increase stresses on the sides of the pipe and decrease stresses on the top and bottom of the pipe. The presence of overburden at the initiation gouge (1:30 position) would not greatly alter the stresses.

prevention programs, rapid detection and shutdown, internal inspections, and land use management. The Board also determined that Federal, State, and local standards for public safety continue to be deficient in these areas.

Pipeline Marking and Surveillance Procedures

TETCO markers.--TETCO installed pipeline markers clearly identifying the pipeline route outside the asphalt plant property, but did not have any markers within the property. The Safety Board realizes that the constant truck and other traffic in the north area of the plant property made the installation of TETCO's standard, 4-foot-tall pole markers impractical. However, the company could have installed its standard marker in selected areas and other types of markers in other plant areas. Standard markers on the earthen berm would not have been subject to damage. The company also could have installed offset markers at the fence line or placed warnings using paint or flush markers on the paved areas over the pipeline. The Board believes that markers on the berm, on the pavement, and other locations within the asphalt plant property might have alerted plant personnel to the location of the pipeline and increased the probability that someone would have notified TETCO before excavating near its pipeline. Upon being notified of planned excavation, TETCO would have had an opportunity to install temporary markings in the area of the excavation, to caution the excavator on how to protect the pipeline, and/or to oversee the excavation. The potential for this accident could have been substantially reduced had the route of the pipeline been marked through the plant.

TETCO's postaccident actions.--Following the 1994 Edison accident, TETCO installed additional fiberglass markers so that the pipeline is marked every 100 feet outside the plant property. Within the plant property, TETCO painted markings on the pavement to show the pipeline location. TETCO is also identifying other industrial and commercial properties on which its pipelines are unmarked to determine effective ways to indicate the locations of lines.

Federal marking requirements.--Although TETCO had no markers identifying the location of Line 20 within the plant property, the company was in compliance with Federal regulations, which exempt a pipeline in a Class 3 or Class 4 location from being marked if the pipeline company has a damage prevention program that meets the Federal standards at CFR 192.614. In 1993, RSPA evaluated TETCO's operations and identified no deficiency in the company's damage prevention program.

Placing markers along pipelines serves not only to notify residents, but also to warn potential excavators of the pipeline. The Safety Board does not believe damage prevention programs should be considered an alternative to pipeline markers; rather markers should be considered an integral part of an effective damage prevention program and used extensively in urban areas where feasible. The Safety Board concludes that exempting pipelines in Class 3 and Class 4 locations increases the potential for excavation damage. The Board believes that RSPA should revise Federal pipeline safety standards eliminating the exception for marking pipelines in Class 3 and 4 locations and establish standards for marking the routes of high-pressure natural gas and hazardous liquid pipelines in urban, industrial, and commercial areas where feasible.

TETCO's Patrol Reporting Procedures.--For several years, activities endangering Line

20 took place on the asphalt plant property unknown to TETCO because its procedures do not require that patrolling employees pay specific attention to the pipeline where it crosses industrial properties. Between 1961 and 1994, the terms of TETCO's easement agreement with the land owners was violated repeatedly by crews continually modifying the grade over the pipeline. Asphalt plant crews dredged the sediment pond, filled in the ponds, built an earthen berm, installed underground piping, and stockpiled plant process materials. Because the TETCO pilot conducting weekly aerial patrols and ground crews periodically walking the line did not report these activities, they either did not observe them or recognize the extent of activity and the potential danger to the pipeline. TETCO's employee operating procedures require its aerial surveyors to report excavation activity, however their field crews document and follow up on the pilot's report only if they are not familiar with the activity. Moreover, patrollers are not required to give specific attention to operations within industrial properties. Consequently, they failed to identify the constantly changing stockpiles and use of mechanized excavation-type equipment within the asphalt plant as operations that might endanger TETCO's pipeline.

TETCO's employee operating manual requires pipeline employees to visit the site of new construction activity and advise construction managers or crews about the pipeline, about potential dangers posed by excavating near the pipeline, and about damage prevention measures. Had TETCO stressed that employees pay better attention to activities within industrial locations and report sitings of all excavations, a TETCO employee likely would have visited the plant to assess the potential danger to the pipeline.

TETCO's postaccident actions.--Since the accident, TETCO has modified its operating procedures to require that employees walk its pipelines to conduct a leakage survey in Class 3 and 4 locations every 2 years. This procedural change will provide employees increased opportunity to observe activities in industrial locations and to inform occupants about the location of its pipelines. The company has also increased the frequency of its aerial patrols to three times a week to minimize the chance that it is not aware of any excavation being performed near its pipelines. However, the company has neither changed employee procedures for documenting reports of excavation and other abnormal events near the pipeline right-of-way nor stressed that employees pay specific attention to activities within industrial properties crossed by the pipeline.

The Safety Board concludes that TETCO's failure to require that aerial surveyors and field personnel give specific attention to activities within industrial properties and documented only new excavation sitings resulted in its personnel failing to recognize the potential for damage to Line 20 by the asphalt plant excavators. The Board believes that TETCO should modify its patrol procedures and documentation requirements to further improve the effectiveness of employee monitoring. TETCO should require its employees to document all patrol observations of excavation activity adjacent to its pipeline and pay specific attention to activities within industrial properties, especially excavation activities. In addition, TETCO field personnel should be required to attach or reference the pilot's report in correlative reports documenting any response action taken to assist management in effectively overseeing implementation of these procedures.

Damage Prevention Programs

Prior Safety Board actions.--Between 1968 and 1972, the Safety Board investigated a

high number of the excavation-caused pipeline accidents having disruptive, tragic consequences. In April 1972, the Board therefore sponsored a pipeline damage prevention symposium, inviting industry and government representatives involved with excavation and pipeline operations to discuss and propose solutions. Many proposals developed at the 1972 symposium led to Safety Board recommendations that resulted in current concepts and systems used to minimize excavation-caused damages to pipelines, such as one-call notification centers. The Safety Board recommended the American Public Works Association (APWA) serve as the umbrella agency to foster a number of initiatives for improving damage prevention measures (figure 11).

The Safety Board also recommended that RSPA require pipeline operators to establish excavation damage prevention programs (P-73-12). In 1982, RSPA implemented regulations for natural gas pipeline operators to develop such programs. The regulations allow operators to comply with regulatory requirements by participating in one-call notification systems. To date, RSPA has not required that liquid pipeline operators establish excavation damage prevention programs.

Since the 1972 symposium, the Safety Board has continued to support the efforts of the APWA, the States, and national organizations dedicated to reducing excavation damages to pipelines. The Board has advocated improving excavation-damage prevention efforts in testimony before State Legislatures and the U.S. Congress, before groups interested in pipeline safety, in talks before trade associations such as the Interstate Natural Gas Association of America (INGAA), the American Public Gas Association, the AGA, and the API. Currently, 42 States have damage prevention laws and 47 have one-call notification systems.

The combined efforts of industry, State commissions, and the Safety Board and other Federal agencies during the 1970s led to a decrease in the number of excavation-caused accidents during the 1980s despite increases in pipeline construction and in urban development near pipeline right-of-ways. Even so, excavation-caused damage remains the largest single cause of pipeline accidents.

Because of the number of excavation-caused accidents in recent years, the Safety Board reviewed several State damage prevention programs in 1994 and identified several recurring, unresolved problems:

- o Excavators must make multiple calls to notify all underground facility operators which might be affected by construction or digging.

Encourage establishment of utility location and coordination chapters (P-73-15);
Develop systems, procedures, and organizational arrangements for coordinating and regulating the activities of all parties working near underground facilities (P-73-16);
Foster adoption of standards on the desired locations of all facilities underground (P-73-17);
Develop standard colors to be used on temporary stakes for identifying the locations of underground facilities (P-73-18); and
Coordinate establishment of a national organization of Utility Coordinating Committees (P-73-19).

Figure 11. Recommendations to APWA in 1973.

- o Most one-call notification centers cannot accurately determine whether planned excavations will likely affect interstate pipelines because reference maps lack sufficient detail. Consequently, pipeline operators must review hundreds of notifications to identify the few proposed excavations that might impact their pipelines.
- o Most State damage prevention programs do not require universal participation, exempting parties such as highway departments and municipal utilities.
- o State programs and Federal regulations enacted by the Occupational Safety and Health Administration (OSHA) and RSPA do not contain effective provisions for identifying and penalizing violators.
- o Some operators lack accurate maps of their systems, which impedes their ability to determine and mark the locations of their buried facilities.

The Safety Board also identified some new State programs that show promise of significantly reducing excavation-caused damage. The States of Arizona, Connecticut, Massachusetts, Minnesota, and Utah require universal compliance with their damage prevention laws, imposing sanctions through administrative rather than judicial action against underground facility operators and excavators found in violation of the provisions of the laws. According to the Massachusetts Department of Public Utilities, in its first year of enforced sanctions, excavation notifications increased 100 percent and the number of pipeline damage incidents decreased from 1,200 to 300. The State collected more than \$300,000 in violation fines, which more than paid for its enforcement efforts. The manager of Connecticut's "Call Before You Dig" one-call excavation notification program reported that improved publicity and enforcement of its damage prevention program resulted in a 60 percent decrease in the number of excavation-caused accidents.

While the damage prevention programs for each of the above-mentioned States differ, they all contain the following provisions that contribute to their effectiveness:

- o Mandatory participation by all affected parties whether private or public;
- o A true, one-stop notification system in which excavators can alert all operators of buried systems;
- o Swift, effective sanctions against violators of State damage prevention laws, and
- o An effective education program for the public, contractors, excavation machine operators, and operators of underground systems that stresses the importance of notifying before excavating, accurately marking buried facilities, and protecting marked facilities when excavating.

After the Edison accident, the U.S. Congress held several hearings²⁹ in 1994 on proposed legislation (H.R. 4394 and S. 2102) directed at minimizing excavation-caused damages to buried facilities, which included actions shown in figure 12. The actions did not result in passage of a national excavation damage prevention statute. The Safety Board urges the Congress to again consider mandating a national excavation damage prevention program to bring uniformity to State programs and to require effective sanctions against violators.

On September 8 and 9, 1994, the Safety Board and RSPA/DOT sponsored an excavation damage prevention workshop attended by more than 375 government and industry representatives. The workshop provided a forum for participants to identify and recommend potential ways to enhance excavation damage prevention programs. Four panels designated by industry and government associations deliberated and achieved consensus findings on the following: the essential elements of an effective one-call notification system; the responsibilities of buried facility operators; the responsibilities of excavators; and ways to effectively administer a damage prevention program (see Appendix E). The Board is analyzing the workshop panels' findings, its previous reports on excavation damage accidents, comments filed by interested parties, and other related documents to develop recommendations for actions necessary to further enhance excavation damage prevention programs nationwide.

Rapid Detection and Shutdown

Following the rupture, operators at Lambertville station did not receive any alarms from Linden station alerting them that the operating pressure had dropped below the low, and then the low-low operating limits. The first indication of a problem on the pipeline was an alarm notifying Lambertville station and Houston Gas Control that the Linden station was off-line. Had the fire at the accident site not been so large and Lambertville operators not seen it, TETCO personnel could not even have determined the general area of the rupture using the company's SCADA system. At best, they could narrow down the general area of the rupture by comparing the compressor stations' metered data. In this case, the distance between Lambertville and Linden was 40 miles.

A nationwide toll-free number system within 1 year.

A State-mandated, statewide excavation damage prevention program that is applicable to all buried facility operators and excavators and which has a single one-call notification system that accomplishes the following services:

- * receives and records information on proposed excavations;
- * informs buried facility operators of intended excavations;
- * informs excavators of the operators that would be notified;
- * provides 24-hour notification coverage;
- * employs mechanisms to inform the public and excavators about the number, requirements, penalties, and benefits of the State program;
- * requires buried facility operators to locate and mark facilities in advance of proposed excavations; and
- * provides mechanisms for enforcement and effective penalties.

Figure 12. 1994 Congressional proposals.

²⁹ Senate Committee on Energy and Natural Resources (April 19, 1994), Senate Subcommittee on Transportation and Related Agencies, Committee on Appropriations (May 5, 1994 and August 3, 1994), Subcommittee on Energy and Power, House Committee on Energy and Commerce (June 23, 1994), and the Public Works Committee of the House (September 22, 1994).

TETCO's postaccident actions.--Following this accident, TETCO modified its employee operating procedure on updating its computer control program to ensure that alarm set points are always defined in its SCADA system. TETCO has also amended its emergency shutdown procedures so that should the company need to shut down the pipeline, supervisors are required to dispatch personnel not only to the upstream valve nearest the emergency, but also to the next closest valve, as personnel become available. In addition, the company is assessing means to ensure its valves operate quickly during emergencies, including ensuring that the gas-assist units function properly during emergencies to avoid the situation that occurred at Edison.

When and if the Lambertville operators received a low-pressure alarm is a moot point because TETCO's employees had no way to promptly shut down the gas flow. The company has few remotely-operated automatic valves on its 10,000-mile system and no automatic or remotely-operated valves on Line 20. Despite the limitations in TETCO's system, the company is in compliance with Federal regulations, which do not contain specific requirements for rapid detection and shutdown of failed pipe segments. TETCO's Senior Vice President stated that despite some reservations, the company is considering using remote-operated valves to improve its ability to rapidly shut down failed pipeline segments. He said TETCO is not considering automatic shutdown valves because it is convinced they are not sufficiently reliable.

The major problem in this accident was the inability of TETCO to shut off the gas flow to the rupture for 2 1/2 hours. The burning gas continued to radiate such great heat that firefighters could not even get close enough to the burning buildings nearest the rupture to combat the blazes, let alone contain or extinguish the fires. Had TETCO had the capability to promptly shut down the flow of gas to the rupture, firefighters could have sooner extinguished the blazes after the pressure in the line diminished and likely could have controlled the spread of the fires to adjacent buildings. The damage in the rupture area likely would have been the same, but the damage to the apartment complex units probably would have been substantially less.

While the changes that TETCO is making may improve their emergency response capability somewhat, the Safety Board believes that the lack of remote-operated and/or automatic valves on its system seriously impedes the company's capability to rapidly stop the gas flow to failed pipeline segments, which can prove to be devastating in an urban environment.

In its background investigation for this accident, the Safety Board reviewed pipeline operator responses to a 1989 RSPA request for comments on the use of ACVs and RCVs (Docket PS-104). The number of valves used by each operator ranged from 4 to 600. Because RSPA did not request specific information, most responses from operators did not contain sufficient information to determine whether operators were currently using ACVs and RCVs, how many valves they were using, how long they had used ACVs or RCVs, or on what length of pipeline they had installed ACVs or RCVs. Sample responses appear in table 9. The Safety Board believes that, based on current uses of ACVs and RCVs by other gas transmission companies, TETCO should assess the risks posed to public safety if failed pipeline segments are not promptly shut down and install ACVs and RCVs, as appropriate, in those areas where risks are the greatest.

Past Safety Board actions.--The Safety Board has addressed the lack of specificity and uniformity in Federal regulations governing pipeline monitoring and the lack of remote or auto-

matic shutdown capability for a number of years. Current Federal regulations require that pipeline operators be able to detect the occurrence of abnormal operating conditions; they do not specify the sensitivity, timeliness, or other criteria for detecting an abnormal condition or for rapidly shutting down failed pipeline segments.

Table 9. Operator Responses to 1989 RSPA Request for Comments.

Pipeline Operator	Comments on ACVs or RCVs
Questar Pipeline Company	Uses RCVs based on a case-by-case review of operating conditions.
Northwest Pipeline Corporation	Uses RCVs at mainline compressor stations and ACVs on its pipeline in the remote areas of western Colorado that are subject to landslides.
Western Gas Supply Company	Has 4 ACVs.
Transcontinental Gas Pipe Line Corporation	Uses RCVs on offshore pipelines.
Lakehead Pipe Line Company, Inc.	Uses both ACVs and RCVs. Reported it initially experienced false closures of RCVs due to lightning, but that it has since resolved the problem.
Gaz Métropolitain, Inc., Montréal, Québec, Canada	Uses both ACVs and RCVs; reported both systems are reliable.
Midcon Corporation	Uses both RCVs and ACVs in its 15,000-mile-long pipeline and has experienced only a few events to test the reliability of these valves. Most of its operating experience with RCVs and ACVs has been through periodic simulations in which the valves performed as designed. Reported a June 22, 1984, event in which a 30-inch gas transmission line ruptured 1.36 miles downstream of a compressor station. Three downstream ACVs sensed the pressure drop and closed, whereupon the station computer initiated a line break sequence and isolated the discharge piping by operating the station RCVs.
ANR Pipe Line	Uses ACVs. To prevent unintended valve closures, establishes activation settings that are outside of the normal operating range for the protected pipeline segment.

In its 1991 report on the accident at Blenheim, New York, the Safety Board expressed concern about the lack of Federally-mandated criteria governing the sensitivity or timeliness of detection for pipeline monitoring systems and recommended that RSPA:

P-91-1

Define the operating parameters that must be monitored by pipeline operators to detect abnormal operations and establish performance standards that must be met to detect and locate leaks.

On October 18, 1991, RSPA wrote the Safety Board, agreeing that "Rapid detection of leaks in gas and liquid hazardous liquid pipelines is essential for operators to prevent accidents or mitigate their consequences." RSPA stated that based on improvements in leak detection efforts using computer-based SCADA systems, it was undertaking a 2-year study beginning in FY-92 to determine whether SCADA systems and SCADA-based leak detection systems should be required on gas and hazardous liquid pipelines. RSPA wrote that it was requesting input for the study from both SCADA system manufacturers and pipeline operators using the systems, and stated, "As a part of the study, RSPA will include an analysis of performance criteria necessary for monitoring systems to detect abnormal operating conditions. The analysis will cover criteria on detection sensitivity, leak detection, and timeliness. The study will lay the groundwork for subsequent rulemaking." On December 20, 1991, the Safety Board classified Safety Recommendation P-91-1 as "Open--Acceptable Response."

In May 1992, RSPA contracted Volpe National Transportation Center to analyze SCADA and computer-generated leak detection systems to determine the feasibility and costs of requiring operators to use SCADA systems with a leak detection subsystem, to determine existing impediments or needed improvements to minimize the time SCADA systems take to detect and locate leaks, and to recommend resolutions for identified difficulties. The study included a literature search, on-site interviews with five equipment vendors, model development to define optimal valve spacing, and a method to evaluate alternative leak detection system performance characteristics to reduce pipeline spill volumes. RSPA anticipates that its report will be complete early in 1995.

Rapid shutdown of failed segments.--The Safety Board began addressing the need for rapid shutdown of failed pipe segments about 25 years ago. In a 1970 report,³⁰ the Safety Board recommended that RSPA:

P-71-01

Conduct a study to develop standards for the rapid shutdown of failed natural gas pipelines and work in conjunction with the Federal Railroad Administration to develop similar standards for liquid pipelines.

RSPA subsequently conducted the study, and on February 12, 1971, the Safety Board classified P-71-01 as "Closed--Acceptable Action." However, RSPA never issued regulations requiring the use of remote-operated valves or other means to rapidly isolate failed pipeline segments. Since 1971, the Safety Board has identified the need to require ACVs and/or RCVs

³⁰ Special Study--*Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown, December 30, 1970* (NTSB/PSS-71/01).

to facilitate rapid shutdown of failed pipelines in a number of accident investigations.³¹

The Safety Board, in its report on the July 8, 1986, accident at Mounds View, Minnesota, recommended that RSPA:

P-87-22

Require the installation of remote-operated valves on pipelines that transport hazardous liquids, and base the spacing of the remote-operated valves on the population at risk.

On February 11, 1987, because of previous and then current Congressional proposals, RSPA issued (Docket No. PS-93, 52 FR 4361) an advance notice of proposed rulemaking (ANPRM) requesting public comment on 18 proposed changes to Federal pipeline requirements, including whether ACVs or RCVs should be installed on pipelines. Many commenters supported the proposal on the assumption that rapid isolation of failed pipe sections would mitigate an emergency; others felt such valves should be installed only where necessary to meet specific operational needs. On May 12, 1987, the Safety Board commented on RSPA's ANPRM, providing pertinent information and resulting safety recommendations from its accident investigations. The Safety Board urged that RSPA establish performance standards for promptly detecting and rapidly shutting down failed pipeline segments. Based on recommendations from its pipeline safety technical advisory committees, RSPA advised the Safety Board that it was initiating a technical study, to be completed in 1988, to assess the feasibility, safety, cost, and effectiveness of the use of ACVs and RCVs in certain pipeline situations, particularly in populated areas.

On May 9, 1989, RSPA issued a Notice of Request for Information (Docket PS-104, 54 FR 20945), in which it stated the information was needed for developing a report to the Congress as required by Public Law 100-561 and to assist RSPA in studying the safety, cost, feasibility, and effectiveness of requiring gas transmission and hazardous liquid operators to install emergency flow restricting devices in existing and future pipeline systems. The notice posed 15 questions on flow restricting devices, SCADA technology, safety of installing RCVs and ACVs, costs of installing new RCVs and ACVs or converting existing valves to RCVs or ACVs, criteria on valve spacing, and demonstration projects that might assist RSPA in selecting which, if any, emergency flow restricting devices. The notice did not seek to determine the commenters' experience and knowledge of ACVs and RCVs, whether they currently used or had ever used such valves, how many ACVs and RCVs were presently installed, when such valves were first installed, or documented cases of such valves properly operating in response to a failure.

³¹ Pipeline Accident Report--*Phillips Pipe Line Company Propane Gas Explosion, Franklin County, Missouri, December 9, 1970* (NTSB/PAR-72/01); Pipeline Accident Report--*MidAmerica Pipeline System Liquefied Petroleum Gas Pipeline Rupture, West Odessa, Texas, March 15, 1983* (NTSB/PAR-84/01); Pipeline Accident Report--*Williams Pipe Line Company, Liquid Pipeline Rupture and Fire, Mounds View, Minnesota, July 8, 1986* (NTSB/PAR-87/01); Railroad Accident Report--*Derailment of Southern Pacific Transportation Company Freight Train on May 12, 1989, and Subsequent Rupture of Calvee Petroleum Pipeline on May 25, 1989, San Bernardino, California* (NTSB/RAR-90/02); Pipeline Accident Report--*Liquid Propane Pipeline Rupture and Fire, Texas Eastern Products Pipeline Company, North Blenheim, New York, March 13, 1990* (NTSB/PAR-91/01).

Of the 74 responders to PS-104, most were liquid pipeline operators. The information provided was insufficient to determine whether each responder had ever used ACVs or RCVs and is currently using either type valve, to determine the number of valves being used, the length of time the valves had been used, and to determine much additional information needed to draw conclusions on the reliability of those valves. For example, ANR Pipe Line responded to RSPA's notice, but did not comment that it has a policy to use ACVs wherever regulations require an emergency valve, that it has used ACVs in its pipelines since the late 1940s, and that it now uses about 600 ACVs. ANR said it had experienced only 2 inadvertent operations of its ACVs in the preceding 10 years.

PEC, TETCO's parent corporation, responded to PS-104 on July 7, 1989, stating that it operates 16,000 miles of pipeline and that "mandatory use of ACV's and RCV's would do nothing to improve pipeline safety in the Natural Gas Industry. Because of wide fluctuations in pressure and flow during normal pipeline operations and the desire to not have inadvertent valves closure, the sensitivity of ACV's would be tuned so low and the operation of RCV's would be so restrictive that anything short of a rupture would not cause valve closure. Such a rupture would usually be ignited, the damage would be done, and the hazard associated with the leaking gas would be contained."

In the Safety Board's report on a May 12, 1989, railroad derailment and subsequent May 25, 1989, pipeline rupture near San Bernardino, California, the Board considered RSPA's inaction on Safety Recommendation P-87-22. Noting RSPA's apparent reluctance and delay in addressing the recommendation until required to do so by Congress, the Safety Board classified Safety Recommendation P-87-22 as "Open--Unacceptable Action," and expressed its continuing concern about the absence of specific Federal provisions addressing timely detection and shut-down of failed pipelines.

In its report on the March 13, 1990, accident at North Blenheim, New York, the Safety Board affirmed the "Open--Unacceptable" status of Safety Recommendation P-87-22, stressing "RSPA should act promptly to establish performance standards for required monitoring to provide for the effective, timely detection of product releases and for the identification of the leak area." The Safety Board urged that RSPA require pipeline operators to install RCVs and ACVs that would afford them the capability to rapidly isolate failed pipe, especially on pipelines near populated areas.

On June 8, 1990, RSPA published a rulemaking proposal (Docket PS-93) in which it stated the justification for requiring RCVs or ACVs uniformly along pipelines appeared to be insufficient. However, because Congress mandated in Public Law 100-561 (October 31, 1988) that RSPA conduct a study to determine whether RCVs or ACVs were needed to enhance pipeline safety, RSPA added that should the study provide a basis for improving pipeline safety, it would initiate new rulemaking. The Congressional mandate also required the Secretary of Transportation to assess the cost and effectiveness of initiating a demonstration project concerning emergency flow restricting devices.

In March 1991, RSPA published *Emergency Flow Restricting Devices Study* in which it concluded that the only emergency flow restricting devices that were technically feasible, effec-

tive, and cost beneficial were RCVs and check valves installed on offshore hazardous liquid pipelines and onshore hazardous liquid pipelines in environmentally sensitive and populated areas. RSPA announced plans to include on its regulatory agenda a project prescribing the circumstances under which emergency flow restricting devices, including remotely controlled valves and check valves, should be installed on hazardous liquid pipeline systems. Pending a thorough review of RSPA's report, the Safety Board classified Safety Recommendation P-87-22 as "Open-Acceptable Response" on December 20, 1991. The Safety Board subsequently reviewed RSPA's study and found it seriously flawed.

The Congressional mandate had stipulated that RSPA determine whether operators should install different types of emergency flow restricting devices in varying circumstances and locations. However because pipeline industry operators questioned the reliability of automatic-closing valves, RSPA eliminated them from study consideration. That action was taken without further study despite evidence cited in the study that 380 automatic-closing valves (about 2 percent of all mainline isolating valves) have been used voluntarily by some pipeline operators and that the Department of Interior's Mineral Management Service has required operators to install such valves on offshore platforms as a safety and pollution control measure for many years.

RSPA also limited its study to hazardous liquid pipelines, concluding "There is no significant benefit from installing remote-control valves on gas transmission pipelines." As reasons for excluding gas pipelines, RSPA noted that in most accidents, the gas ignites upon escaping, therefore rapid isolation would not prevent the primary effect of a pipe failing, that is, fire. Also, if no ignition source is nearby, natural gas dissipates because it is lighter than air. RSPA also dismissed considering RCVs on gas transmission lines because isolating a small leak in an unpopulated area might require cutting off the gas supply to a number of distribution customers. RSPA's report did not consider the consequences of natural gas pipelines rupturing in urban areas or of high pressure gas-fed fires emanating radiant heat for an extended time in densely populated areas.

After severely limiting the scope of the study, RSPA concluded that a demonstration project was not necessary since the test would involve only RCVs and check valves on liquid pipelines. Many of the report's conclusions were not definitive findings because RSPA did not gather information essential to making feasibility assessments and it did not consider the effectiveness of RCVs in combination with existing or emerging SCADA systems (figure 13).

RSPA's cost/benefit evaluations did not assess the benefit of using RCVs or ACVs in combination with existing pipeline monitoring systems or advanced leak detection systems. RCVs cannot minimize the effects of pipe failures until the operator is able to detect the failure. Likewise, the value of effective pipeline monitoring systems that promptly detect an emergency is diminished if the operator is unable to promptly stop gas or hazardous materials from flowing to the failure.

On September 2, 1992, RSPA advised the Safety Board that Public Law 102-508 requires RSPA to complete a study on emergency flow restricting devices (EFRDs) by October 1994 for hazardous liquid pipelines and issue a final rule by October 1996. RSPA's study must assess the effectiveness of EFRDs (including RCVs and check valves) and equipment used to detect and

locate pipeline ruptures and to minimize product releases from pipeline facilities. Congress mandated that RSPA conduct the survey and assessment within 2 years of enactment and take final action within 2 years of completing the survey and assessment. On May 11, 1993, the Safety Board reviewed RSPA's response and classified Safety Recommendation P-87-22 "Open--Acceptable Response."

On January 12, 1994, RSPA issued an ANPRM (Docket No. (PS-133, 59 FR 2802) soliciting comments to a series of questions on emergency EFRDs and leak detection systems to assist it in developing requirements. RSPA stated that responses received by April 19, 1994, would be used to develop a rule-making proposal. RSPA stated that it had been concerned for some time with rapid leak detection on hazardous liquid pipelines and the optimum placement of EFRDs. It reviewed past actions on this issue since 1978, including its March 1991 study, and advised that it was soliciting information and data by posing a series of questions rather than conducting a traditional research survey of a selected number of respondents so it could obtain a broader base of data and to accelerate the regulatory process.

The Safety Board believes that RSPA's defective 1991 study report on RCVs and ACVs caused the Congress to inappropriately limit considerations of EFRDs to hazardous liquid pipelines in Public Law 102-508. The Safety Board's review of RSPA's 1991 study and the Edison accident makes clear that RSPA needs to reconsider its actions on using RCVs and ACVs as main line valves to promptly limit the flow of natural gas to failed pipeline segments, especially when in urban or environmentally sensitive areas. To that end, the Safety Board classifies Safety Recommendation P-87-22 as "Closed--Unacceptable Superseded" and urges RSPA to expeditiously develop requirements on using RCVs and ACVs to provide for the prompt shutdown of failed pipe segments in both liquid and natural gas transmission systems, especially on pipelines in urban and environmentally sensitive areas. Pending final action by RSPA, the Safety Board urges the natural gas and hazardous liquid pipeline associations to work with their members to develop programs that will reduce to a minimum the time required to isolate failed pipeline segments in the more densely populated areas, including modifying existing valves for automatic or remote operation.

- Releases from pipelines can be significantly reduced by remote control valves only where a modern pipeline monitoring system with a well-designed leak detection subsystem exists.

- It is feasible to convert manually operated valves for remote operation on pipelines in rural areas; however, the cost effectiveness of doing so cannot be determined because a compilation of the location of valves on existing pipelines is not readily available.

- It is feasible to convert manually operated valves for remote operation on pipelines in urban areas, the costs are estimated to be \$1.59 of realized benefits for every \$1.00 of retrofit cost and \$1.24 of realized benefits for every \$1.00 of cost for new valve installations; however, such valves will be ineffective without installation of an effective monitoring system with a well-designed leak detection subsystem.

- Based on the Mounds View accident and the report from the National Institute of Standards and Technology, ... safety and environmental protection would be increased by the installation of emergency flow restricting devices at specific locations. However, the number of these locations and the impact on the industry and the public from their installation is not known.

Figure 13. Examples of RSPA study conclusions.

Public Education Programs

Lack of public awareness.--TETCO's public awareness actions were typical of most natural gas transmission companies. TETCO annually provides information about its pipeline and related safety advice to all land owners, including the owners of Durham Woods Apartments and Quality Materials, Inc., through mailers and handouts and to the general public through newspaper notices. Yet, interview and questionnaire responses obtained after the Edison accident indicate many of the asphalt plant employees and most Durham Woods Apartment residents were not aware of the presence of the TETCO pipeline.

The Edison accident raises questions as to whether TETCO's and other pipeline operators' public education programs reach the necessary audiences. The Board does not believe pipeline operators can practicably disseminate public education information to all occupants and employees of commercial and industrial properties adjacent to pipelines. Rather, it believes the notified land owners should further disseminate information about the pipeline. The management at Durham Woods Apartments could easily have included pipeline safety information to tenants when they rented their units. The management of Quality Materials, Inc., could have posted pipeline information on an employee bulletin board or included a briefing about the pipeline in an employee safety meeting. In this accident, the lack of information did not affect the survivability. However, had they been provided such information, the apartment residents may have better prepared for evacuating the buildings and plant employees may have exercised greater caution when excavating or storing materials in the area of the pipeline. The Safety Board believes that TETCO and other pipeline operators should advise land owners about the importance of further disseminating its safety information to tenants and employees who live or work on land adjacent to high-pressure pipelines.

Industry actions.--After the Edison accident, the Board of Directors of the Interstate Natural Gas Association of America (INGAA), an organization of gas transmission pipeline operators, developed a 16-point safety education and emergency preparedness program, which its Public Affairs Committee is currently implementing and includes the actions shown in figure 14.

Past Safety Board actions.--Following its investigation of a March 15, 1983, pipeline rupture in West Odessa, Texas,³² the Safety Board posed, "How can a reasonable degree of public awareness of the presence of buried pipelines be maintained?" In that accident, an owner/resident in a new housing development and his relative were drilling holes with an auger to plant trees when they struck and ruptured a liquid petroleum gas (LPG) pipeline. The escaping gas initially pooled and vaporized, forming an explosive gas-in-air mixture that was ignited. The LPG being blown into the air by the pressure in the line then ignited, forming a fireball that engulfed the relative operating the auger and the resident's home. The auger operator and the four residents of the mobile home were burned fatally; the owner sustained serious burns and died 5 days later. The fire also threatened the residents of the home on the adjoining lot. They escaped with minor burns only by breaking and fleeing through a back window in their home.

³² National Transportation Safety Board Mid-America Pipeline System Liquefied Petroleum Gas Pipeline Rupture, West Odessa, Texas, March 15, 1983 (NTSB/PAR-84/01).

- Redistribute the INGAA "call-before-you-dig" radio and television public service announcements, revised to reflect one-call legislation if it is passed.
- Purchase time during periods of high viewership to air the INGAA "call-before-you-dig" public service announcements in key markets.
- Produce and distribute an INGAA video on how to handle a pipeline emergency aimed at local emergency preparedness personnel.
- Along with the emergency response personnel video, distribute to INGAA members a model pipeline safety briefing plan, including written materials, for use by local officials.
- Prepare articles on recognizing and protecting pipelines and place them in specialty publications to reach excavators, farmers, general construction managers, highway contractors, firefighters, emergency response personnel, and public officials.
- Produce and make available to schools and cable TV an INGAA safety video(s) showing how pipelines are engineered, constructed, tested, and marked and how to recognize a leak and what actions to take.
- Design and make available to members for mass mailings and distribution to homeowners and residents near pipeline rights-of-way condensed, simplified safety information on gas transmission pipelines.
- Test the effectiveness of as many INGAA and company materials on pipeline safety as possible.
- Conduct polls to assess the results of industry-wide INGAA public education efforts on safety.
- Distribute nationally service stories that cite a pipeline's safety record and ask public cooperation in damage prevention program.
- Provide members sample newspaper and Yellow Pages ads on safety, the "call-before-you-dig" program, and other topics for local use.
- Compile and make available to members an annotated listing of companies offering services such as media training, mock emergency exercises, emergency preparedness courses and emergency response audits; and of companies offering focus group, polling, and audit services for use in assessing the company's public education programs.

Figure 14. Selected actions of the INGAA pipeline safety program.

In its report about the 1983 West Odessa accident, the Safety Board observed that because liquid and gas pipelines are buried and indicated only by markers, the general public is rarely aware of their presence, let alone the potential hazards that pipelines represent. The Board found that while existing operator public education programs had some positive measures, their focus was primarily toward current landowners, rather than prospective users of the land or others who might be affected by the presence of a pipeline. Since 1984, the Safety Board has continually urged RSPA to implement improved pipeline public education programs. A summary of RSPA's actions and Safety Board responses follows.

In the Safety Board's May 12, 1987, response to RSPA's ANPRM, Docket No. PS-93,

which contained a proposal that conspicuous signs be required at road crossings, the Board stated that its accident investigations showed that markers alone were not sufficient for educating the public about liquid and gas pipelines. The Board advised that RSPA require pipeline operators to implement public education programs that "aid the public to recognize the existence of the pipeline, to understand the hazards presented by materials transported in the pipeline, to recognize potential and actual emergency conditions and to report such conditions to appropriate local authorities, and to understand what actions should be taken by persons becoming aware of an emergency condition for their safety and for the safety of others nearby...." The Safety Board stressed that RSPA should develop requirements for public education programs that specify desired safety objectives and criteria for evaluating an operator's performance, stating, "Operators should be allowed to implement whatever program(s) they believe will be effective for achieving the safety objective so long as they meet the criteria established in the regulations." The Board also cautioned, "...each operator should be required to develop a means for periodically assessing the effectiveness of its program(s) and the DOT should also determine the adequacy of such programs during its operator compliance reviews."

RSPA subsequently withdrew its proposal to require sign posting,³³ stating that considering present and planned requirements on providing the public with information about the location and potential hazards and considering the additional cost and uncertain benefits of requiring operators to notify landowners directly about pipeline locations, it did not believe additional rulemaking was warranted. RSPA stated it would monitor the efficacy of existing public education programs and propose necessary rule changes in a separate rulemaking proceeding.

The Safety Board again questioned the effectiveness of pipeline operator public education programs in its March 27, 1990, report³⁴ on a series of accidents in Kansas and Missouri. Noting the successful communication measures in such public education programs as drug interdiction and seatbelt promotion, the Board recommended that RSPA:

P-90-21

Assess existing gas industry programs for educating the public on the dangers of gas leaks and on reporting gas leaks to determine the appropriateness of information provided, the effectiveness of educational techniques used, and those techniques used in other public education programs and based on its findings, amend the public education provisions of the Federal regulations.

On September 28, 1990, RSPA responded that it would explore funding sources in Fiscal Year 1991 and, should funds be found, would task its Transportation Systems Center in Cambridge, Massachusetts, to assess existing gas industry programs. On May 7, 1991, the Board classified Safety Recommendation P-90-21 as "Open--Acceptable Response."

³³ See *Disposition of Safety Proposals* on Docket PS-93 (55 FR 23514).

³⁴ National Transportation Safety Board Pipeline Accident Report, *Kansas Power and Light Company Natural Gas Pipeline Accidents September 16, 1988 to March 29, 1989*, (NTSB/PAR-90/01).

On April 9, 1992, RSPA advised the Safety Board that because of current and projected budget constraints, it considered the assessment "low priority" for funding and asked that Safety Recommendation P-90-21 be classified as "Closed-Reconsidered." RSPA suggested asking an industry trade association to assess the gas industry public education programs. On October 29, 1992, the Safety Board told RSPA staff that it would be inappropriate for RSPA to delegate the assessment responsibility to an industry association, whereupon RSPA indicated it would reconsider what actions it might take to achieve the objective of the recommendation.

On April 5, 1993, RSPA issued Advisory Bulletin ADB-93-02, which directed gas pipeline facility owners and operators to review and assess their continuing education programs for customers and the public "to ensure that they are in compliance with the provisions of 49 CFR 192.615(d)." The bulletin included information about Safety Board accident investigations and cited, in part, Safety Recommendation P-90-21. On April 22, 1994, the Board expressed appreciation for RSPA's efforts toward improving pipeline safety, but advised, "Although the bulletin probably prompted most operators to review their programs, the Safety Board does not regard it as responsive to Safety Recommendation P-90-21 or consistent with the discussions on October 29, 1992, between RSPA and Safety Board staff." The Board encouraged RSPA to perform the evaluations necessary to accomplish the recommended action and advised that it had classified Safety Recommendation P-90-21 "Open--Unacceptable Response."

The Safety Board believes that the Edison accident accentuates the need that RSPA take an active role in ensuring that pipeline operator public education programs are effective in providing the information that the public needs to recognize where pipelines are located, potential hazards, how to recognize and report an emergency pipeline condition, and how to safely evacuate the area. Consequently, the Safety Board affirms the "Open--Unacceptable Action" status, reiterates Safety Recommendation P-90-21, and urges RSPA to initiate action within 1995 to meet the intent of the recommendation.

Internal Inspection of Pipelines

TETCO's inspections.--TETCO internal inspections of Line 20 exceeded Federal standards, which did not even require that pipelines be pigged, let alone specify performance criteria for conducting the inspections. According to testimony from company officials, even though TETCO is not required by regulation to conduct in-line tool inspections, the company has long been an advocate of using internal inspection instruments because "We feel they provide a lot of valuable data for our corrosion control program." Officials stated that pigging the line enables them to determine the cathodic protection status of a given line. They can also better direct their monitoring efforts by identifying pipe sections where the pig registers several indications versus segments where the tool records few or no indications.

Past Safety Board actions.--In its 1987 report³⁵ on two pipeline ruptures in Kentucky, the Safety Board expressed concern about the lack of periodic requalification requirements in Federal

³⁵ National Transportation Safety Board 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-87/01).

pipeline safety regulations. Noting that many thousand miles of liquid and gas pipelines were equipped or, with minor modifications, could be equipped to accommodate internal inspection equipment, the Board made several recommendations that RSPA promulgate internal inspection requirements for new pipelines and pipelines undergoing major modification (see figure 15).

On April 29, 1987, RSPA advised the Safety Board that the issues in Safety Recommendations P-87-6 and -7 were related to topics in an ANPRM (Docket PS-93) that it had issued earlier in 1987, and that it was currently reviewing the comments it had received to develop its position on new inspection or testing requirements.

The Pipeline Safety Reauthorization Act of 1988 (P.L. 100-561, October 31, 1988) subsequently required that the Secretary of Transportation assess and report to the Congress by April 30, 1990, findings on the feasibility of requiring periodic instrumented internal inspections of gas and hazardous liquid transmission pipelines. The Act further required the Secretary to establish by regulation that the design and construction of new and replaced gas and hazardous liquid transmission pipelines provide for the passage of internal inspection instruments.

On May 9, 1989, RSPA issued a Notice (54 FR 20948, Docket No. PS-105) requesting information to broaden its assessment. On June 8, 1990, RSPA announced that it had begun the Congressionally-required study and that it planned to determine the inspection interval based on the following factors: location; size, age, manufacturer, and type of pipe; nature and volume of materials transported; frequency of leaks; present and projected population adjacent to pipelines; and climate, geologic, and environmental conditions. RSPA also advised that it would require that new and replacement pipe be designed to accommodate the passage of internal inspection instruments.

In its 1990 report on the train derailment and subsequent pipeline rupture at San Bernardino, California, the Safety Board again addressed the safety advantages of using internal instrumented pipeline inspections. The Board observed that had the pipeline operator internally inspected the pipeline after the derailment, the company would have determined that the pipeline was damaged and could have averted the subsequent pipeline rupture by repairing the pipeline before repressurizing it. The Safety Board acknowledged RSPA's pledge to consider action to implement Safety Recommendation Nos. P-87-6 and -7 and require operators to design new and rebuilt pipelines to accommodate internal inspection instruments. Even so, the Safety Board classified both Safety Recommendations "Open--Unacceptable Action" because of RSPA's

Require operators of both gas and liquid transmission pipelines to periodically determine the adequacy of their pipelines to operate at established maximum allowable operating 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. (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. (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. (P-87-6)

Require that all new gas and liquid transmission pipelines be constructed to facilitate the use of in-line inspection equipment. (P-87-7)

Figure 15. 1987 Recommendations issued to RSPA on internal inspection of pipelines.

apparent reluctance to consider the recommendations until required to do so by the Congress and because of RSPA's delay in initiating action.

In a 1992 report to Congressional committees,³⁶ the U.S. General Accounting Office (GAO) listed several benefits of smart pig inspections and concluded that the inspection instrument would reduce incidents in pipelines that could accommodate it. The GAO also observed that despite a 1988 Congressional mandate that RSPA perform a feasibility study on smart pigs and promulgate regulations requiring their use by May 1990, Federal regulations still did not address internal inspections of pipelines. The GAO concluded that RSPA needed to complete the mandated feasibility study and regulations.

On November 20, 1992, RSPA issued an NPRM on the internal inspection of pipelines. On February 1, 1993, the Safety Board urged RSPA to finalize its proposal because the correct and timely use of appropriate in-line internal inspection equipment could provide essential information on a pipeline's condition that could not be obtained otherwise. In its final rule, which was issued on April 12, 1992, RSPA required that only new and replacement gas transmission and hazardous liquid pipelines be designed to accommodate internal inspection devices. RSPA received two petitions for reconsideration from INGAA and AGA to limit the length of gas pipeline that would be affected when pipe modifications were made. On May 12, 1994, RSPA notified INGAA, AGA, and API that it was suspending enforcement of the rule until further notice. However, RSPA encouraged operators to voluntarily modify any obstructions in the line segment to accommodate smart pigs whenever replacing line segments. On September 30, 1994, RSPA issued a response to the petitions modifying the rule to exclude offshore gas transmission lines and gas transmission lines in less populated areas.

RSPA indicates that it is planning to issue an NPRM proposing that internal inspection devices or other equivalent inspection methods be required on gas pipelines in high-density population areas and on hazardous liquid pipelines in highly populated areas, environmentally sensitive areas, and in navigable waterways.

Based on the detail and accuracy of the findings in the 1986 and 1994 internal inspections of TETCO's Line 20, the Safety Board continues to advocate periodic inspections of high-pressure pipelines, especially in urban and environmentally sensitive areas, to assess their fitness for continued safe operation. With the RSPA requirement that new and most refitted gas and hazardous liquid pipelines accommodate the passage of internal inspection devices, the potential for this technology to benefit pipeline safety will greatly increase. Therefore, the Safety Board classifies Safety Recommendation P-87-6 and P-87-7 "Closed-Acceptable Response." However, RSPA needs to take final action to require that internal inspection technology be used periodically to assess the condition of pipelines and to establish criteria that operators can use to determine how often pipelines should be internally inspected. The Board affirms the "Open-Acceptable Response" classification of Safety Recommendation P-87-4, reiterates it, and urges RSPA to complete action on this important issue in 1995.

³⁶ United States General Accounting Office, Report to Congressional Committees, *Natural Gas Pipelines, Greater Use of Instrumented Inspection Technology Can Improve Safety*, Washington, D.C. (GAO/RCED-92-237).

Federal Minimum Safety Standards.--Many Federal pipeline safety regulations are no more than general statements that lack sufficient guidance to pipeline operators about necessary actions to achieve a safety objective. In this accident, applicable regulations that lacked specificity included operator emergency plans for monitoring pipeline operations to effect emergency shut down of system segments to minimize hazards to life and property [(192.615(a)(6))]; establishing and maintaining liaison with public officials [192.615(b)]; and establishing continuing educational programs for customers, government organizations, and the public [192.615(d)].

The Safety Board addressed this issue in its March 27, 1990, report,³⁷ in which it concluded that operators would better adhere to pipeline safety standards if they clearly understood the requirements and if RSPA and the States had a means for evaluating compliance. The Board observed, "Although the RSPA considers its regulations to be performance-oriented requirements, many are no more than general statements." The Board noted that regulations lacking specific objectives and measurable standards for performance made it difficult for a gas operator to understand the need for a program or to determine if the program implemented complies with requirements. The Board concluded:

RSPA needs to evaluate and amend, as necessary, its pipeline safety regulations to provide requirements that contain both readily understandable safety objectives and specific criteria against which the performance of a gas operator can be readily measured. Where RSPA finds that it is unable to include ... specific criteria for measuring operator compliance, it should develop a means to provide information that describes the types of actions expected of an operator for compliance and advise the operator of the basis RSPA will use in assessing compliance.

Based on its findings, the Safety Board recommended that RSPA:

P-90-15

Evaluate each of its pipeline safety regulations to identify those that do not contain explicit objectives and criteria against which accomplishment of the objective can be measured; to the extent practicable, revise those that are so identified.

and

P-90-16

Develop and make public through advisories or other means guidance detailing the types of actions expected of pipeline operators and the basis that will be used in assessing compliance for all pipeline safety regulations that do not contain explicit objectives and criteria against which accomplishment is to be measured.

On September 28, 1990, RSPA advised the Safety Board that in FY-91, a National Asso-

³⁷ National Transportation Safety Board Pipeline Accident Report, *Kansas Power and Light Company Natural Gas Pipeline Accidents September 16, 1988 to March 29, 1989*, (NTSB/PAR-90/01).

ciation of Pipeline Safety Regulators (NAPSR)³⁸ committee, in cooperation with RSPA, was undertaking a comprehensive review of the gas pipeline safety regulations to identify regulations needing clarification, to make regulations enforceable, and to correct inconsistencies. The review would include identifying gas pipeline safety regulations that did not contain explicit objectives and criteria against which operators could measure accomplishment. Upon completing the review, RSPA would initiate a regulatory project to revise regulations to the extent practicable. Regarding P-90-16, RSPA indicated the NAPSR committee would identify safety regulations that could not be sufficiently revised to provide explicit objective and measurement criteria. RSPA would then issue Alert Notices and public interpretation letters and revise its operation and enforcement manual to detail "acceptable procedures" in areas lacking specific criteria. On May 7, 1991, the Safety Board advised RSPA that it classified both safety recommendations "Open--Acceptable Response," pending the outcome of the NAPSR's review.

On February 18, 1992, RSPA advised the Safety Board that it had tasked the NAPSR committee to identify the 20 most significant regulations that were unenforceable due to lack of clarity and that the committee's report was expected by the end of 1992. RSPA indicated that after reviewing the report, it would propose appropriate changes to the regulations in late 1993. RSPA noted that three of its staff were members of the Gas Piping Technology Committee (GPTC), which develops operator guidance on actions to take to meet Federal requirements. RSPA stated that its staff members would ensure that the GPTC is aware of the NAPSR review and take the results into account in developing guidance where appropriate. On March 8, 1993, the Safety Board asked RSPA to periodically review the NAPSR committee's efforts to ensure that all regulations, not just 20, were clarified, and to provide a copy of NAPSR's final report when it was available. The Safety Board advised RSPA that both safety recommendations would remain "Open--Acceptable Response," pending receipt and review of the NAPSR report.

After the NAPSR completed its report, RSPA issued a Notice of Request for Information (Docket PS-124) on November 9, 1993, asking for comment by January 10, 1994, on 20 priority items and 13 technical corrections needing clarification. Because RSPA's actions have not resulted in any tangible safety improvement in the 4 years since they were issued, the Safety Board classifies Safety Recommendations P-90-15 and -16 as "Open--Unacceptable Action."

Adequacy of Pipe Toughness Properties

The Line 20 pipe separated as a brittle (cleavage) fracture, rather than a ductile fracture, indicating the steel in the pipe had low toughness properties. The brittle failure of Line 20 in effect left two ends of the 36-inch-diameter pipeline wide open, allowing high-pressure gas to flow initially from two directions (Lambertville station and Linden station) to the rupture site, where the gas escaped into the air, feeding the fire. The back flow of gas from Linden station did subside substantially as the pressure in the pipeline segment was exhausted; however, gas continued to flow from Lambertville station for 2 1/2 hours until TETCO crews were able to

³⁸ The NAPSR is a committee composed of State regulatory personnel who administer pipeline safety programs in their respective states.

close the mainline valves and the pressure in the line from the valve site to the open end of the pipe was exhausted.

Had the pipe metal been ductile instead of brittle at the operating temperature, the pipe might have withstood greater damage without failure. Had the pipe had better toughness properties, the pipe may have leaked instead of catastrophically fracturing over a long distance. The Charpy impact test, an indicator of a material's resistance to brittle fracture, showed that any failure of this pipe would be brittle because its transition temperature (about 175°F) was greater than its normal operating temperature.

The Safety Board is concerned that neither current industry codes nor Federal regulations contain minimum standards for pipe toughness properties. The current API specifications³⁹ for line pipe includes fracture toughness testing standards, however, the section is only a supplemental reference that operators may use when ordering pipe.

The Safety Board mostly recently addressed the issue of pipe toughness properties in the report of its investigation of a 1990 pipeline rupture near North Blenheim, New York.⁴⁰ In that accident, the Board found that increased stresses from settlement caused the circumferential brittle failure of an 8-inch diameter API 5L X42 steel pipeline because its low fracture toughness made the pipe susceptible to brittle fracture at normal operating temperatures. The steel in the pipe had a high ductile-to-brittle transition temperature, 150°F. The Board also noted that because most pipe steel has low fracture toughness, it is susceptible to fracture at almost all operating temperatures. The Safety Board recommended that RSPA:

P-91-2

Require pipeline operators to conduct analyses, before moving pressurized pipelines, to determine:

- o the extent to which the pipe may be safely moved,
- o the specific procedures required for the safe movement of the pipe,
and
- o the actions to be taken for protection of the public.

On October 18, 1991, RSPA advised the Safety Board that it recognized the potential problems associated with moving pipelines, including the increased risk of failure because of low fracture toughness. On June 22, 1992, RSPA issued an Alert Notice notifying all gas and hazardous liquid pipeline operators of factors to consider before moving a pipeline, which contained:

³⁹ API 5L, November 1, 1992.

⁴⁰ For further information, see Pipeline Accident Report--*Liquid Propane Pipeline Products Pipeline Company, North Blenheim, New York, March 13, 1990*, (NTSB/PAR-91/01).

Determine the toughness of the pipeline if known, or if not known, assume that the material in the pipeline is brittle. If the pipeline is known to be or assumed to be brittle, consider that, in addition to those factors developed by Battelle ["Guidelines for Lowering Pipelines While in Service"], lack of toughness may indicate a reason not to move the pipeline.

RSPA also advised the Safety Board that it planned to review its current regulations to determine what changes were needed in the Federal regulations. On October 20, 1992, the Safety Board classified Safety Recommendation P-91-2 as "Closed--Acceptable Action."

Other studies and professional papers have addressed the lack of standards for pipeline toughness properties. In a 1993 paper⁴¹ presented at the Eighth Symposium on Line Pipe Research, the authors discussed a brittle fracture propagation in a 36-inch-diameter API 5L X52 steel natural gas transmission pipeline at a meter station about 60 miles north of Calgary, Alberta, Canada, on January 8, 1992. The fracture propagated in both directions from a tee, resulting in a rupture almost 1,225 feet long. The report attributed the catastrophic failure to the property of the steel lacking resistance to crack propagation.

In their paper, "Brittle Behavior of Pipelines,"⁴² presented at a 1994 AGA conference authors Naylor and Davidowitz discussed the 1990 brittle fracture failure at North Blenheim, New York, a 1989 brittle fracture failure at Hellgate, New York City, New York, and the findings of a 1992 questionnaire on steel pipe toughness to member companies of the AGA's Distribution Engineering Committee.

In the Hellgate accident on December 29, 1989, a 30-inch-diameter steel gas transmission pipeline operating at 350 psig and 10°F suffered a brittle failure when shock waves from a nearby explosion fractured the low-toughness steel main, opening 11 feet of pipeline. Flames from the gas-fed fire soared 200 feet high, destroyed two nearby buildings, and damaged 50 automobiles. Two fatalities and one injury resulted from the accident.

Of the twenty-three member companies responding to the AGA Distribution Engineering Committee's questionnaire on steel pipe toughness, seven indicated they had toughness properties in their pipe specifications; two reported that they were testing new and existing pipe for toughness; and five indicated that they were considering toughness criteria in their steel specifications.

The paper presented at the 1994 AGA conference also reported that the New York Gas Group, an organization representing most gas companies in New York State, had formed a special subcommittee to work on a cooperative project with the New York Public Service Com-

⁴¹ "Main Line Failure Resulted from Combination of Minor Causes," Stefano C. Chiovelli, David V. Dorling, Alan G. Glover, David J. Horsley of NOVA Corporation of Alberta, Calgary, Eight Symposium on Line Pipe Research, September 26-29, 1993, Houston, Texas.

⁴² C. E. Naylor and David Davidowitz, *Brittle Behavior of Pipelines*, American Gas Association Conference, May 8-11, 1994, San Francisco, California.

mission⁴³ to consider establishing pipe toughness standards. The cooperative group is proposing to require that steel used in 10-inch-diameter or larger pipelines operating at 30 percent or more of SMYS pressure meet the API's supplementary requirement SR5 for shear values at 50°F. The authors concluded that the steel specifications for new pipelines should include the ductility testing requirements contained in API specification 5L, supplementary requirements SR5 or SR6.

The Safety Board is concerned that no fracture toughness standards are required for new pipe being installed, especially in urban areas. Increased toughness properties can protect the public by preventing pipe failures or by minimizing the consequences of failure. Should a pipe having increased toughness properties fail, the opening in the pipe will be smaller, which results in gas being released at a lesser rate within a given time. With a lesser rate of gas being released, the resulting flame is smaller, which, in turn, reduces the threat to the surrounding area from the effects of radiant heat and affords firefighters greater opportunity to protect people and buildings. The Safety Board believes that RSPA should develop toughness standards for all new pipe in gas and hazardous liquid pipelines to reduce the potential for failure and to minimize the consequences of pipe failure, especially in urban areas.

Survivability.--A combination of factors contributed to no fatalities or few serious injuries directly resulting from this accident, including:

Time of Accident.--Had the rupture occurred during daylight hours, it is likely that several deaths would have occurred and injuries would have been far more severe. Had people been in the asphalt plant, or in the nearby parking lot or children's playground of the apartment complex, they likely would have been injured by flying debris and the fire's radiant heat.

Distance to Closest Residence.--Had the rupture occurred farther east, for example, within 100 feet of apartment buildings, people might have become trapped within burning buildings. At a minimum, they would have had far less time to evacuate and would have been subjected to much greater radiant heat while evacuating. A rupture closer to the complex would likely have resulted in fatalities, a greater number and more severe injuries, and more property damage.

Factors that contributed to the prompt evacuation of apartment residents included their being alerted timely by the noise of the rupture and of debris pelting their buildings and by the terrifying sight of the 500-foot-high flames within yards of their complex.

Land Use Management

Postaccident Ordinances.--When TETCO planned Line 20 through the Edison Township area, the company used, as a minimum, Class 3 design standards and routed the pipeline through less densely populated areas. While New Jersey statutes preclude construction of new high-

⁴³ The New York Public Service Commission has pipeline safety regulatory authority over intrastate natural gas pipeline operators in New York State.

pressure pipelines near buildings, there are no regulatory provisions preserving the separation distance by limiting the construction of buildings adjacent to existing pipelines. Even though TETCO complied with the New Jersey requirements when constructing the pipeline, the company, like all other pipeline operators, had no control over the use of lands adjacent to its pipelines. Consequently the separation distance from buildings established during construction was reduced through adjacent land development that was condoned by local governments.

The Safety Board observed that after the accident, Edison Township officials reacted much like other local authorities who have experienced a disaster that threatened public safety. In less than 6 months after the Edison rupture, on August 24, 1994, local authorities enacted new zoning and development ordinances that enable planning officials to determine whether proposed development will encroach on pipeline rights-of-way.

Section 86-6 of the Code of the Township of Edison (Edison Code) prohibits, with few exceptions, any building or land disturbance within 75 feet of any distribution, gathering, or transmission line. Section 88-28 of the Edison Code requires that, unless exempted under certain ordinances, all development applications must be reviewed by the Planning Board and/or Board of Adjustment. The application must contain the following information about the subject property: pipeline easements, pipeline rights-of-way, and the location, size, SMYS, MAOP, location class, and operating hoop stress as a percentage of SMYS of any pipeline. The application must also disclose the following for any land within 75 feet of the subject property: approximate location of easements, rights-of-way, and pipelines; operating stress of the pipelines; and pipeline cross sections and profiles, including existing and proposed conditions and improvements.

The Safety Board believes that while the speed with which Edison Township attempted to enact public safeguards is commendable, the ordinances adopted will not necessarily guarantee the adequacy of public safety. The new ordinances were developed without conducting comprehensive safety analyses to identify and evaluate the threats that pipelines pose to public safety. The actions of Edison Township to increase building setbacks from pipelines may reduce the potential for excavation damage to pipelines, but will not change the consequences should a high-pressure pipeline rupture in a urban area.

Urban Development.--Records indicate that a comparatively small percentage of pipelines are located in urban areas. No available source lists the exact mileage, however, RSPA estimates⁴⁴ that of the 272,200 miles of natural gas and liquid high pressure pipelines, only 7 percent, or 19,000 miles of natural gas and 11,500 of liquid pipelines, are in urban areas. RSPA annual reports on the pipeline industry also show that the miles of natural gas and liquid mainlines have slightly decreased in recent years, probably the result of lines being consolidated when companies merged (figure 16).

Despite a low percentage of mainline pipelines being located in urban areas, the potential

⁴⁴ RSPA based its estimate on a market study conducted by a steel pipe manufacturer. See *Emergency Flow Restricting Devices Study*, a RSPA study mandated by P.L. 100-561.

hazard to public safety is increasing because of residential growth and development. In the case of the rupture area, the character of the land had changed dramatically from when the pipeline was constructed. In 1961, the asphalt plant and its surrounding structures was an small, isolated industrial complex surrounded by farmland and forests. In 1994, extensive urbanization had occurred within 1 mile of the rupture point. Census statistics show that New Jersey is now the most densely populated State with an average 1,200 people per square mile. Middlesex County, in which Edison Township is located, has grown to a density of 2,162 people per square mile.

To meet the energy needs of burgeoning urban populations, pipeline operators have almost doubled the mileage of distribution lines in the United States during the past 20 years (figure 16). Industry publications indicate that pipeline operators will continue to expand their operations in urban areas. For example, TETCO's parent corporation, PEC, doubled its investments in market-expansion projects between 1992 and 1994 and currently has several on-going programs that will add more than 150 miles of high-pressure pipelines in primarily urban areas.

The continuing development in urban areas and an increase in the number of pipelines serving urban areas heightens the Safety Board's concern that excavation-caused pipeline ruptures, such as the Edison accident, might increase in frequency. The Safety Board believes that effective land-use controls are necessary to minimize the likelihood that pipelines will be damaged during land modification and development. Such controls could limit to acceptable levels the risks posed to public safety by high-pressure pipelines.

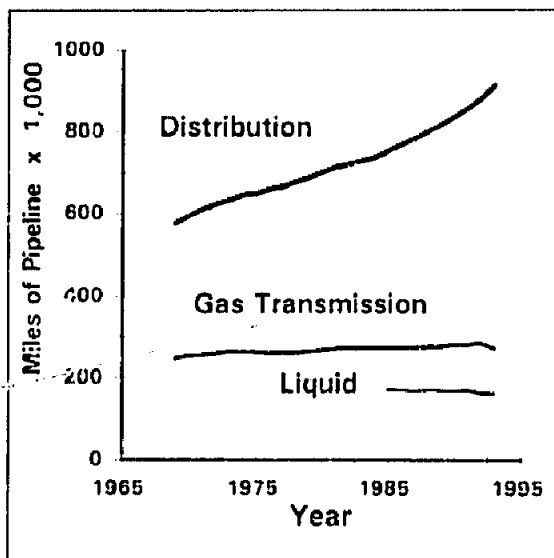


Figure 16. Pipeline mileage in the United States.

Past Safety Board Actions.--The Safety Board has previously addressed the need for local and State government agencies to consider the public safety risks presented by pipelines in urban settings and to control the land use and type of building construction on properties adjacent to high-pressure pipelines. Several communities and research organizations have reviewed safety concerns related to development near high pressure pipelines and made recommendations for improvement. Even so, many of the recommended solutions have not been implemented by Federal, State and local governments.

As a result of the West Odessa accident investigation, the Safety Board concluded that new public policy should be developed to improve public safety as it relates to the proximity of pipelines to populated areas, including:

- Defining the role of Federal, State, and local governments concerning land planning for land adjacent to pipelines;

Placing restrictions on the use of land adjacent to pipelines;

Determining what information should be communicated to prospective users about adjacent pipelines; and

Informing prospective users about the existence of and potential hazards of nearby pipelines.

The Board further concluded that crafting public policy for land development adjacent to pipelines would require extensive research and would involve incorporating the views from many interests, including the general public, pipeline operators, land developers, local, State, and Federal government agencies, and many others. Noting the ability of the Transportation Research Board (TRB) of the National Academy of Sciences to bring diverse groups together to formulate practical public safety policy, the Safety Board recommended that the TRB:

P-84-30

Assess the adequacy of existing public policy for surface and subsurface use of land adjacent to pipelines that transport hazardous commodities to provide reasonable public safety. Based on the findings of the assessment, develop a recommended policy to correct identified deficiencies in current policy.

In a February 5, 1987, ANPRM (Docket No. PS-93, Notice 1, 52 FR 4361) RSPA considered, in part, whether its pipeline safety regulations should prohibit new pipelines within 150 feet of any permanently inhabited facility; and whether it should require siting standards for hazardous liquid pipelines similar to those for natural gas pipelines. RSPA noted that its regulations do not address the location of new pipelines other than to caution hazardous liquid pipelines to avoid inhabited areas as far as practicable. On the issue of siting standards, RSPA stated that while its hazardous liquid pipeline regulations contain no siting standards, many of its safety standards increase in stringency as pipelines enter more populated areas.

In 1988, the TRB published *Pipelines and Public Safety (Special Report 219)*,⁴⁵ which synthesized policies and practices for enhancing public safety near pipelines through damage prevention programs, land-use measures, and emergency preparedness programs. The TRB concluded that government and industry apply these measures unevenly. The report focused on ways to strengthen and extend existing practice and recommended that local and State governments enact the improvements listed in figure 17. The report also included model/sample documents for damage prevention legislation, right-of-way agreements, State legislation for subdivision plan review, guidelines for subdivision developments near pipeline rights-of-way, and local setback ordinances. The Safety Board found the report responsive to Safety Recommendation P-84-30 and on December 22, 1988, classified it "Closed--Acceptable Action."

⁴⁵ National Academy of Sciences, Transportation Research Board, *Pipelines and Public Safety (Special Report 219)*, Washington, D.C. The report is available through the TRB's publications catalog.

On June 5, 1990, (Docket PS-93, Notice 2, 55 FR 23514) RSPA reported that while a few responders recognized that setbacks would mitigate accident consequences, most focused on the difficulty and great expense of obtaining and controlling development on a right-of-way as big as a football field. After reviewing the report, RSPA "wholeheartedly" supported the TRB's recommendation that local governments should determine the appropriate use of land near pipelines and enact laws to prevent development on pipeline rights-of-way. On the issue of siting standards, comments were about evenly divided. Opponents maintained that siting standards based on operating pressure or stress level would not add to the safety of liquid pipelines. The RSPA stated that land development decisions, including establishment of minimum setback distances between pipelines and buildings, is the traditional role of local governments not an appropriate role for the Federal Government. Consequently, it withdrew the land-use proposal from further consideration. On the siting issue, RSPA stated it believed that the hazardous liquid standards already contain many safety standards that vary in stringency according to population characteristics.

In its 1990 report on the train derailment and subsequent pipeline rupture near San Bernadino, California, the Safety Board again reviewed local government controls on the use of lands adjacent to hazardous transportation facilities, such as high-pressure pipelines. In those accidents, the Safety Board determined that the land was designated for residential use in 1955 and a subdivision plat was filed in the county records that year. In 1967, a railroad was constructed abutting a portion of the subdivision in which houses were not yet constructed. In 1970, a hazardous liquid pipeline was constructed in an easement across the back portion of yet unused subdivision lots that abutted the railroad. At the time of the accidents, houses were constructed and occupied throughout the subdivision.

San Bernardino had an existing framework for determining land use to protect residents from natural and man-made hazards, which did not address use of land near high-pressure pipelines. On July 20, 1990, the Safety Board recommended that the City of San Bernardino:

1. Enact damage prevention statutes and improve compliance by requiring permitting agencies to obtain proof of notification from persons securing building or excavation permits, increasing contractor liability and pipeline operators who ignore notice requirements, and clarifying enforcement responsibility.
2. Prohibit construction of structures on pipeline rights-of-way and ensure access to pipelines is unobstructed.
3. Institute a referral and approval procedure that requires pipeline operator review of subdivision plans, site plans, and variances for all properties that have a pipeline easement.
4. Modernize land records systems to ensure that the types of easements, easement boundaries, and holders of easements by parcel is readily accessible by to local planners.
5. Prepare planning guidelines, in consultation with pipeline operators and developers, for safely integrating pipelines easements into development projects and protecting the lines during construction; incorporate these guidelines in comprehensive plans, zoning ordinances, and building codes.
6. Consider building setbacks and low-density development near transmission pipeline rights-of-way in densely populated areas with high concentrations of pipeline mileage where the risks of damaging a pipeline may be sufficiently great, and the consequences sufficiently severe, to warrant special measures; provide development bonuses to compensate the developer for loss of developable property.

Figure 17. TRB recommendations.

I-90-18

Revise the existing plan for land use to account for the location of railroads and high-pressure pipelines.

On September 6, 1990, the City of San Bernardino responded that it (1) set broad guidelines for area development in the general plan and through zoning subdivision regulations, regulates the use of specific properties; (2) instituted procedures for zoning and subdivision approval that involve pipeline operators in a plan review and approval process; and (3) mapped and will keep records of pipeline locations. On November 21, 1990, the Safety Board advised the City of San Bernardino that it classified Safety Recommendation I-90-18 as "Closed--Acceptable Action."

The Safety Board evaluated the 1988 TRB report in light of the accident at San Bernardino and found that although the report was specifically developed, in principle, for pipelines, the discussions on land use also applied to railroads. The Board therefore recommended that the National Association of Counties and the National League of Cities:

I-90-20

Inform your members of the land-use guidance for enhancing public safety contained in the National Research Council's Special Report 219, "Pipelines and Public Safety," and encourage them to develop and implement policies to protect public safety for lands adjacent to pipelines and railroads.

On December 18, 1990, the National Association of Counties (NAoC) advised the Safety Board that it included in its publication "County News" an article advising of the TRB report and encouraged members to obtain and use the report. On February 21, 1991, the Safety Board classified the NAoC's action relative to Safety Recommendation I-90-20 as "Closed--Acceptable Action." The National League of Cities (NLC) did not respond and the Safety Board classified the NLC inaction as "Closed--Unacceptable Action."

The Safety Board is aware of several efforts of agencies and localities to deal with the threats posed to public safety by pipelines in urban areas. In December 1975, the Department of Housing and Urban Development issued *Safety Considerations in Siting Housing Projects*, which provides guidance for designing and siting HUD-insured or HUD-assisted housing and HUD-assisted meeting or gathering place structures near pipelines that transporting materials presenting explosion, fire, or toxic threats to safety. The 1975 guidebook examines risk for both liquid and gas transmission pipelines.

In 1984, HUD published policy guidance (24 CFR 51, subpart C) on siting HUD-assisted projects near handling operations involving conventional fuels or chemicals of an explosive or flammable nature. Although this guidance did not pertain to pipelines, the Safety Board believes State and local governments should develop the same types of policies to lessen the risks posed as population densities increase near pipelines. Effective HUD policies include the following:

- o Establish safety standards which can be used as a basis for calculating acceptable

- o separation distances (isolation zones);
- o Alert those responsible for the siting of HUD-assisted projects to hazards;
- o Provide guidance for identifying the most prevalent hazardous operations;
- o Provide technical guidance for evaluating the degree of danger from possible explosion and thermal radiation; and
- o Provide technical guidance for determining acceptable separation distances from hazards.

A 1982 paper, "Risk-Based Zoning for Toxic-Gas Pipelines," published in *Risk Analysis*, addresses buffer zones for pipelines. It offers a probabilistic approach to zoning and identifies factors that should be considered, uses available accident and other data to assist in making judgments, compares alternative approaches, and helps to quantify intuitive risk considerations. The authors developed a risk-based model to aid the Alberta, Canada, government in determining the size of buffer zones, and in adopting a zoning regulation that includes graded setbacks. The paper states that without the risk-based approach large buffers are needed to assure that all danger is avoided by a "worst-case", or even an "average-case" scenario. It cautions that implementing large buffers in urban areas is costly.

The Safety Board is aware of two counties, Santa Barbara County, California, and Fairfax County, Virginia, that are considering actions to increase pipeline safety through land-use regulations. Santa Barbara County stated planning policy states "...a transmission pipeline should not pose a level of risk that unduly inhibits local development or unduly jeopardizes the safety of county residents." It uses risk analyses and subdivision regulations, zoning, and site plan requirements to improve pipeline safety. Fairfax County advocates the use of graded setbacks, such as those used in Alberta, Canada. Fairfax County planning practices do not quantify risk, but employ land-use controls, including requiring accurate location of pipelines throughout the land approval and development process to reduce risk from excavation damage.

Fairfax County proposes to require, on a case-by-case basis, building setbacks from pipelines. It has not yet established guidance procedures that will achieve reasonably uniform risk reductions. The Fairfax County Deputy Zoning Administrator acknowledged the limitations of only using pipeline setbacks. In a November 1, 1994, memorandum to the Planning Commissions Underground Utilities Committee, he advised that a single setback distance cannot be justified because the damage area from a pipeline accident is affected by a variety of factors, including the pipe size, pressure, and substance transported. The TRB's Special Report 219 also noted that determining a single distance for safe setback from liquids and gas transmission pipelines is complex because the damage radius of an accident is affected by the size of the pipe, the pressure at which it is operated, the material carried, the depth of cover, the climate, and the character of the terrain near the pipeline. The report noted that so much difficulty is associated with developing a setback standard that applies to a variety of local circumstances yet is not prohibitively expensive that the decision to require setbacks requirements has generally been left to localities. The Report recommended that the determination of appropriate measures be based on a careful assessment of the probable increased risk to people and property if development takes place near high-pressure pipelines.

Use of safety analyses and risk assessments to develop land-use controls are feasible.

The HUD has used these analysis techniques to determine what buffers and other measures are necessary to protect life and property should a pipeline rupture near facilities for which it is responsible. Alberta, Canada, has used and Santa Barbara County is considering using such techniques to resolve their concerns about the proximity of pipelines to people. However, safety analyses and risk assessments are costly and would likely burden smaller communities to the extent they would not be performed or if performed, they would likely not be comprehensive.

RSPA has also recognized the need to use risk analyses to assess the adequacy of current actions to protect public safety in urban areas from threats posed by the aging hazardous liquid and gas transmission pipeline infrastructure. In its FY-94 budget, it included funds to develop means of protecting the aging pipeline infrastructure through a risk-based prioritization process. The funds approved for the study had not been used by the time of the Edison accident.

In August 1994, RSPA used the aging infrastructure study funds to contract the New Jersey Institute of Technology (NJIT) to perform a study on methods to reduce the risks and enhance pipeline safety and environmental protection with respect to the siting and proximity of pipelines to the public and sensitive environments. RSPA noted that the existing population-based requirements, which were considered adequate for assessing risk in the past, proved to be inadequate in the Edison, New Jersey accident. RSPA acknowledged the need to reevaluate pipeline safety regulations in 49 CFR Parts 192 and 195 as they related to the proximity of pipelines to populated and environmentally sensitive areas. RSPA noted that land use, including population concentration and surrounding environment, should be considered in the evaluation. The contract requires that the NJIT:

- Develop a framework in safety and environmental pipeline areas to be compared with the Federal requirements, with industry practice, and with foreign regulations in the areas of rehabilitation and retrofitting practices and land use and siting requirements.
- Assemble two groups consisting of no more than seven members to provide technical assistance on factual matters and to give the NJIT feedback needed in completing the analytical requirements of the contract. One group shall be composed of individuals having pipeline engineering and technical expertise and the other of representatives from the environmental community and representatives having expertise in New Jersey land use and zoning matters.
- Study the probability of failures that can occur on gas transmission and hazardous liquid pipelines and identify the factors that cause pipeline failures. The NJIT shall consider failures that might occur anywhere along the pipeline corridor, but shall concentrate on failures that occur at high risk areas and environmentally sensitive areas, such as urban areas and water bodies used for human consumption.

In conducting its study, the Institute is to identify and rank the factors that affect the causes of pipeline accidents and rank those factors according to their occurrence probability. Specifically included in the 20 factors to be ranked are land use policy, accuracy of pipeline

mapping, and third party damage to pipelines. The work statement provides flexibility for considering issues not specifically listed.

The Safety Board agrees that comprehensive safety and risk analyses are needed to identify actions that potentially can improve public safety near high-pressure pipelines and to assess the potential effectiveness of each. The Board believes the RSPA contract offers significant potential for rationally quantifying the risks posed to public safety by high-pressure pipelines in urban areas, for assessing the effectiveness of government requirements in reducing identified risks to acceptable levels, and for identifying what additional actions may be needed and by whom. The contract does not require any assessment on whether building standard improvements for structures near pipelines would reduce public safety risks. The Safety Board believes that the Edison accident demonstrates that buildings with improved resistance to heat and to shock would provide improved evacuation opportunity and save lives. RSPA should amend its contract to require an assessment of the affect of building standards on public safety for buildings located adjacent to high-pressure pipelines.

The Safety Board urges RSPA to make the NJIT study widely available to local and State governments. However, the Board recognizes that completion of and dissemination of the study will not of themselves ensure that local and State governments enact the recommended actions. The Safety Board therefore reviewed the objectives and capabilities of several associations to determine which would be best able to translate the study results into guidance suitable for implementation by local and State governments and to work with and encourage them on implementation.

The American Public Works Association (APWA), which has been effective in progressing national issues, has more than 24,000 members. Slightly more than half of its members work for municipalities and about 7,000 members are engineers and/or planners. The association operates under specialized groups, called institutes, which address specific public work areas. For example, the Utilities Location and Coordination Council addresses the accommodation of utilities in rights-of-way and has published and distributed a guide for the Federal Highway Administration of the U.S. Department of Transportation. The APWA has Institutes for Municipal Administration and for Buildings and Grounds, the combined purposes of which include most every facet of the New Jersey Institute's study purpose.

The International City/County Management Association (ACMA) is a professional and educational organization of more than 7,800 appointed administrators and assistant administrators serving cities, counties, and other local governments and regional entities. The association provides technical assistance, training, and passes information through its publications to disseminate information and data of benefit to local government activities.

The civil engineer has long had a responsibility in the planning and development of American cities. The American Society of Civil Engineers has several divisions such as the Urban Planning and Development Division, the Special Standards Division, and the Pipeline Division which address issues that are included in the New Jersey Institute's study. The ASCE was founded in 1852, and has become a major professional association in planning and development of properties. For example, its Standards Committee is concerned with infra-

structure standards and is presently developing standards for subdivisions and site planning. On issues of national concern, the ASCE has adopted policy statements, position papers, or resolutions on subjects of concern to the civil engineering profession. In 1992, the National Conference of States on Building Codes and Standards, in its request for the development of national consensus standards to address land use and subdivision development, recognized the ASCE as a most appropriate organization to undertake the development of land-use standards.

The American Planning Association (APA) has members nationwide. Its membership consists of professional planners and others interested in rural and urban planning issues. The APA certifies planners through the American Institute of Certified Planners and it serves also as an information clearinghouse for them. The APA prepares studies and technical reports, and conducts seminars and conferences to advance professionalism among planners.

The APWA, the ASCE, the ICMA, and the APA worked together as an expert group on the HUD-sponsored model land development standards study and on developing model state enabling legislation. These agencies have other joint activities, such as the ASCE-APWA Joint Committee and the APWA Liaison Utility Location and Coordination Council on which an ASCE member serves.

The Safety Board believes that local and State governments should take several actions on land use practices that have been already assessed and recommended by the TRB study without waiting on the results of the Institute's study. Actions such as preventing building encroachments on pipeline rights-of-way, requiring review by pipeline operators of planned land use developments and modifications when near high-pressure pipelines, integrating pipeline easement information and pipeline protection requirements into development plans and into local zoning ordinances and building codes, and improving government land records to include pipeline easement information in a form that is readily accessible to local planners and others can contribute to improved public safety near pipelines now. The Safety Board believes the above referenced associations represent most all interest that might be affected by the TRB study recommendations and urges them to convey to their members the public safety concerns demonstrated by the Edison, New Jersey, accident and urge that they implement land use improvements recommended in the TRB study.

Further, the Safety Board believes the above referenced associations have the capability for translating technical study results into practical guidance and model programs and statutes for implementation by local and State governments. Consequently, the Safety Board believes that they should work jointly in developing the Institute's study results into workable programs, guidelines, and model statutes for implementation by local and States governments. The Safety Board believes that for this work to be accomplished both timely and effectively, one of the associations must provide both the leadership and administrative support. The Safety Board believes that the APWA, because of its past performance in coordinating national work projects and because it already has working relationships with the ASCE, the ICMA, and the APA, should take on the coordination responsibilities.

CONCLUSIONS

Findings

1. On the day of the accident, Line 20 did not fail as a result of human error, as a result of excessive operating pressure, or from excavation damage caused before 1986.
2. TETCO's Line 20 was gouged by excavation equipment, such as a backhoe, at an undetermined time after the pipeline was internally inspected in 1986.
3. The mechanically-induced gouge at the rupture initiation likely created a crack in the gouge that grew to a critical size, most likely as a result of metal fatigue.
4. Exempting pipelines in any class location from Federal marking requirements increases the potential for excavation damages. Clearly marking the route of Line 20 through the asphalt plant property may have increased the likelihood that the employees of Quality Materials, Inc. notified TETCO prior to excavating.
5. Periodic instrumented inspection of pipelines can identify most types of injurious defects and damages before a rupture occurs.
6. A pipe metal having good toughness properties may have sustained the gouges without failure or sustained a substantially smaller failure opening that would have reduced the rate at which gas was released. The brittle failure of Line 20 allowed the release of the natural gas at the maximum possible rate.
7. Although many TETCO requirements and procedures surpassed those required by Federal regulations, the company's surveillance procedures did not stress that employees identify excavation activities within industrial locations that could endanger its pipeline.
8. Quality Materials, Inc., did not advise its employees about the presence of or potential hazards posed by the pipeline within the plant property, or implement precautionary measures to protect Line 20 from excavation damage by employees.
9. TETCO's lack of automatic- or remote-operated valves on Line 20 prevented the company from promptly stopping the flow of gas to the failed pipeline segment, which exacerbated damage to nearby property.
10. RSPA's study on reducing public safety risks with respect to pipeline siting, if modified to assess the effect of building standards for structures near pipelines, offers significant potential for identifying necessary additional actions.
11. The public will not benefit from the safety improvement recommendations developed in RSPA's public safety risk study without guidance containing implementation procedures and without motivation from associations representing local governments.

12. Local and State government agencies could significantly improve public safety near high-pressure pipelines by implementing actions recommended in the TRB's Special Report 219.

13. RSPA has repeatedly failed to address public pipeline safety concerns in a timely manner.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the rupture of Texas Eastern Transmission Corporation's Line 20 in Edison Township, New Jersey, was mechanical damage to the exterior surface of the pipe that reduced the wall thickness and likely created a crack in the gouge that grew, most likely through metal fatigue, to critical size. Contributing to the rupture were the brittle properties of the pipe material at the operating temperature. Contributing to the severity of the accident was the inability of Texas Eastern Transmission Corporation to promptly stop the flow of natural gas to the rupture.

RECOMMENDATIONS

As a result of its investigation of this accident, the National Transportation Safety Board makes the following safety recommendations:

--to the Research and Special Programs Administration:

Expedite requirements for installing automatic- or remote-operated mainline valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments. (Class II, Priority Action)(P-95-1)

Develop toughness standards for new pipe installed in gas and hazardous liquid pipelines, especially in urban areas. (Class II, Priority Action)(P-95-2)

Eliminate the exception for marking pipelines in Class 3 and 4 locations from existing standards and establish standards for permanent markings that identify the location of high-pressure natural gas and hazardous liquid pipelines in urban, industrial, and commercial areas, where marking is feasible. (Class II, Priority Action)(P-95-3)

Expedite the completion of the study on methods to reduce public safety risks in the siting and proximity of pipelines, modify that study to include consideration of building standards, and make the completed study widely available to local and State governments. (Class II, Priority Action)(P-95-4)

-- to Texas Eastern Transmission Corporation:

Install automatic- or remote-operated equipment on mainline valves in urban areas to provide for rapid shutdown of failed pipeline segments. (Class II, Priority Action)(P-95-5)

Require pilots to document all patrol observations of excavation activity adjacent to your pipelines, noting specifically excavation activities within industrial properties, and require that the pilot's report be attached or referenced in correlative reports documenting any response taken. (Class II, Priority Action)(P-95-6)

Modify the information in the annual mailings of your public education pipeline safety program to encourage recipients to disseminate the pipeline safety precautions to their tenants and employees who reside and work on property adjacent to high-pressure pipelines. (Class II, Priority Action)(P-95-7)

-- to the American Public Works Association:

Develop, in coordination with the American Society of Civil Engineers, the International City/County Management Association, and the American Planning Association, model programs and statutes and/or guidelines for local and State governments to implement the recommendations from the New Jersey Institute of Technology's study on enhancing public safety near high-pressure pipelines. (Class II, Priority Action)(P-95-8)

Advise your Members of the public safety concerns addressed in this accident report and urge them to implement the land-use improvement recommendations in the Transportation Research Board's Report 219. (P-95-9)(Class II, Priority Action)

-- to the Interstate Natural Gas Association of America:

Encourage your Members to modify the information in the annual mailings of their public education pipeline safety program to encourage recipients to disseminate the pipeline safety precautions to their tenants and employees who reside and work on property adjacent to high-pressure pipelines. (Class II, Priority Action)(P-95-10)

Encourage your Members to develop programs, which include the modification of existing valves for remote or automatic operation, that will reduce to a minimum the time required to stop the flow of natural gas or hazardous liquids to failed pipeline segments, especially those segments in urban or environmentally sensitive locations. (Class II, Priority Action)(P-95-11)

--to the Association of Oil Pipe Lines:

Encourage your Members to modify the information in the annual mailings of their public education pipeline safety program to encourage recipients to disseminate the pipeline safety precautions to their tenants and employees who reside and work on property adjacent to high-pressure pipelines. (Class II, Priority Action)(P-95-12)

Encourage your Members to develop programs, which include the modification of existing valves for remote or automatic operation, that will reduce to a minimum the time required to stop the flow of natural gas or hazardous liquids to failed pipeline segments, especially those segments in urban or environmentally sensitive locations. (Class II, Priority Action)(P-95-13)

--to the American Petroleum Institute:

Encourage your Members to modify the information in the annual mailings of their public education pipeline safety program to encourage recipients to disseminate the pipeline safety precautions to their tenants and employees who reside and work on property adjacent to high-pressure pipelines. (Class II, Priority Action)(P-95-14)

Develop programs, which include the modification of existing valves for remote or automatic operation, that will reduce to a minimum the time required to stop the flow of natural gas or hazardous liquids to failed pipeline segments, especially those segments in urban or environmentally sensitive locations. (Class II, Priority Action)(P-95-15)

--to the American Gas Association:

Encourage your Members to modify the information in the annual mailings of their public education pipeline safety program to encourage recipients to disseminate the pipeline safety precautions to their tenants and employees who reside and work on property adjacent to high-pressure pipelines. (Class II, Priority Action)(P-95-16)

Encourage your Members to develop programs, which include the modification of existing valves for remote or automatic operation, that will reduce to a minimum the time required to stop the flow of natural gas or hazardous liquids to failed pipeline segments, especially those segments in urban or environmentally sensitive locations. (Class II, Priority Action)(P-95-17)

--to the American Society of Civil Engineers:

Cooperate with the American Public Works Association on developing model programs and statutes and/or guidelines to aid local and State governments to implement the recommendations from the New Jersey Institute of Technology's study on enhancing public safety near high-pressure pipelines. (Class II, Priority Action)(P-95-18)

Advise your Members of the public safety concerns addressed in this accident report and urge them to implement the land-use improvement recommendations in the Transportation Research Board's Report 219. (Class II, Priority Action)(P-95-19)

--to the International City/County Management Association:

Cooperate with the American Public Works Association on developing model programs and statutes and/or guidelines for local and State governments to implement the recommendations from the New Jersey Institute of Technology's study on enhancing public safety near high-pressure pipelines. (Class II, Priority Action)(P-95-20)

Advise your Members of the public safety concerns addressed in this accident report and urge them to implement the land-use improvement recommendations in the Transportation Research Board's Report 219. (Class II, Priority Action)(P-95-21)

--to the American Planning Association:

Cooperate with the American Public Works Association on developing model programs and statutes and/or guidelines to aid local and State governments to implement the recommendations from the New Jersey Institute of Technology's study on enhancing public safety near high-pressure pipelines. (Class II, Priority Action)(P-95-22)

Advise your Members of the public safety concerns addressed in this accident report and urge them to implement the land-use improvement recommendations in the Transportation Research Board's Report 219. (Class II, Priority Action)(P-95-23)

Also as a result of its investigation of this accident, the National Transportation Safety Board reiterates to the Research and Special Programs Administration:

P-87-4

Require operators of both gas and liquid transmission pipelines to periodically determine the adequacy of their pipelines to operate at established maximum allowable operating 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.

P-90-21

Assess existing gas industry programs for educating the public on the dangers of gas leaks and on reporting gas leaks to determine the appropriateness of information provided, the effectiveness of educational techniques used, and those techniques used in other public education programs and based on its findings, amend the public education provisions of the Federal regulations.

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

JAMES E. HALL
Chairman

JOHN A. HAMMERSCHMIDT
Member

ROBERT T. FRANCIS II
Member

January 18, 1995

APPENDIX A
INVESTIGATION AND DEPOSITION

Investigation

The National Transportation Safety Board was notified on March 24, 1994, of the rupture of a 36-inch-diameter gas transmission pipeline and subsequent fire at Edison Township, New Jersey. Upon being notified, the Safety Board dispatched an investigation team from Washington, D.C., comprising investigation groups for pipeline operations, metallurgy, survival factors, and human performance. Later, the Board established an investigation group for land use planning.

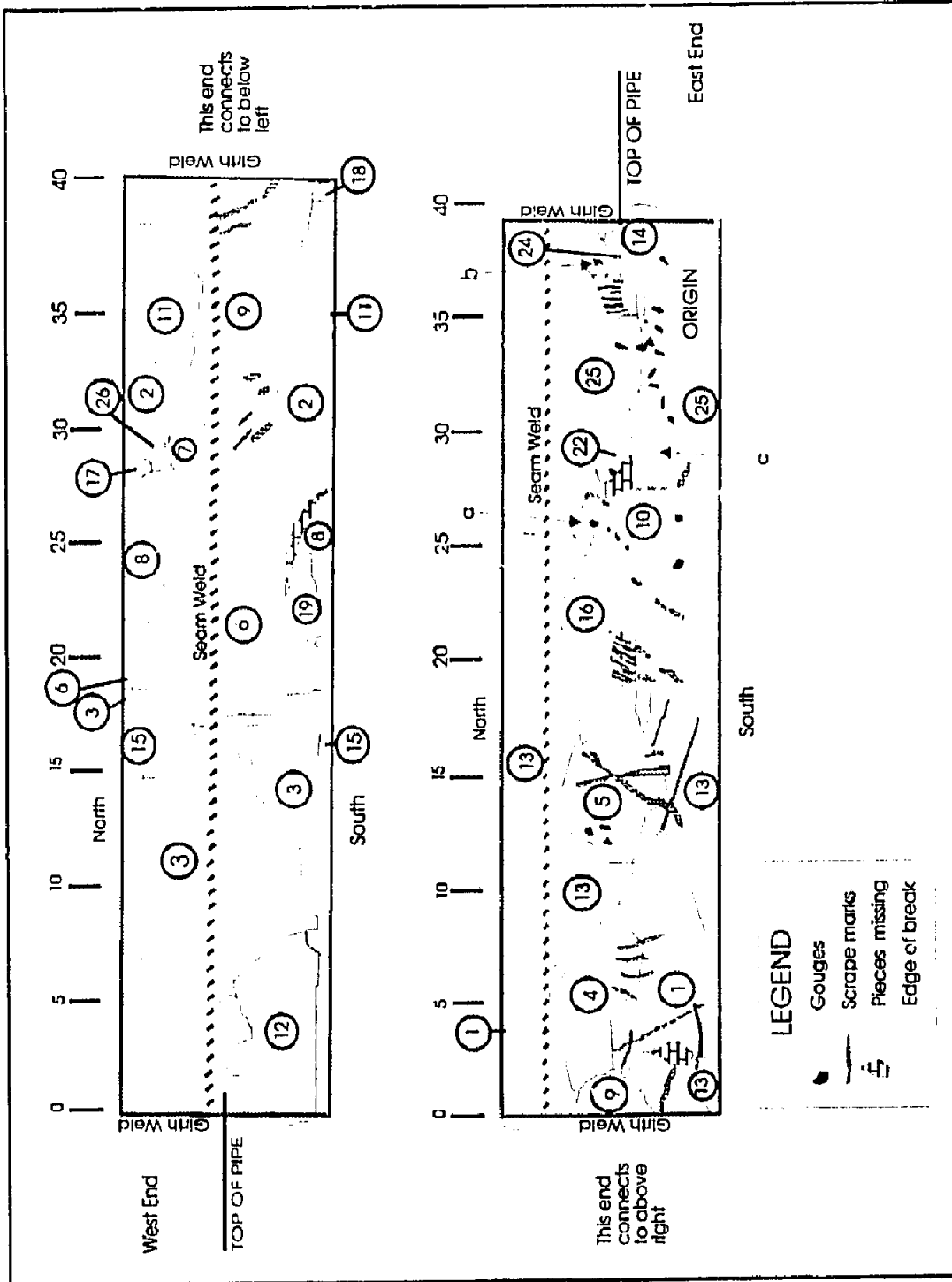
Hearing

The Safety Board did not conduct a public hearing in conjunction with this investigation.

Deposition

The Safety Board took depositions in conjunction with this investigation in Washington, D.C., on August 9, 1994. Parties to the proceedings included Texas Eastern Transmission Corporation, Edison Township, Office of Pipeline Safety, the U.S. Department of Transportation, New Jersey Board of Regulatory Commissioners, and Middlesex County, New Jersey.

APPENDIX B RECONSTRUCTION OF PIPE FRAGMENTS



APPENDIX C REGULATIONS APPLICABLE TO LINE 20

§192.5 Class locations.

(a) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d)(2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit in a multiple dwelling building is counted as a separate building intended for human occupancy.

(b) A Class 1 location is any class location unit that has 10 or less buildings intended for human occupancy.

(c) A Class 2 location is any class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is:

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(e) A Class 4 location is any class location unit where buildings with 4 or more stories aboveground are prevalent.

(f) The boundaries of the class locations determined in accordance with paragraphs (a) through (e) of this section may be adjusted as follows:

(1) A Class 4 location ends 220 yards from the nearest building with four or more stories aboveground.

(2) When a cluster of buildings intended for human occupancy requires a Class 3 location, the Class 3 location ends 220 yards from the nearest building in the cluster.

(3) When a cluster of buildings intended for human occupancy requires a Class 2 location, the Class 2 location ends 220 yards from the nearest building in the cluster.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-56, 52 FR 32925, Sept. 1, 1987]

Subpart L--Operations

§192.601 Scope.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

§192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) *Each operator shall keep records necessary to administer the procedures established under §192.605.*

(c) The Administrator or the State Agency that has submitted a current certification under section 5(a) of the Natural Gas Pipeline Safety Act with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

[35 FR 13257, Aug. 9, 1970, as amended by 192-66, 56 FR 31090, July 9, 1991, Amdt. 192-71, 59 FR 6579, Feb. 11, 1994]

§192.605 Procedural manual for operations, maintenance, and emergencies

Each operator shall include the following in its operating and maintenance plan:

(a) Instructions for employees covering operating and maintenance procedures during normal operations and repairs.

(b) Items required to be included by the provisions of Subpart M of this part.

(c) Specific programs relating to facilities presenting the greatest hazard to public safety either in an emergency or because of extraordinary construction or maintenance requirements.

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(d) A program for conversion procedures, if conversion of a low-pressure distribution system to a higher pressure is contemplated.

(e) Provision for periodic inspections to ensure that operating pressures are appropriate for the class location.

(f) Instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §191.23 of this subchapter.

Amendment 192-71 adds the italicized portions of §192.603 and §192.605 in it's entirety on February 11, 1995, except for §192.605 (b)(9) which became effective on March 14, 1994.

Each operator shall include the following in its operating and maintenance plan:

(a) *General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least one each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.*

(b) *Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and operations.*

(1) *Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part..*

(2) *Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part..*

(3) *Making construction records, maps, and operating history available to appropriate operating personnel.*

(4) *Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.*

(5) *Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.*

(6) *Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.*

(7) *Starting, operating and shutting down gas compressor units.*

(8) *Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedure when deficiencies are found*

(c) *Abnormal operation. For transmission lines, the manual required by paragraph(a) of this section must include safety when operating design limits have been exceeded:*

(1) *Responding to, investigating, and correcting the cause of:*

(i) *Unintended closure of valves or shutdowns;*

(ii) *Increase or decrease in pressure of flow rate outside normal operating limits;*

(iii) *Loss of communications;*

(iv) *Operation of any safety device; and*

(v) *Any other malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property.*

(2) *Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.*

(3) *Notifying responsible operator personnel when notice of an abnormal operation is received.*

(4) *Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.*

(d) *Safety-related condition reports. The manual required by paragraph(a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially*

Appendix C

may be safety-related conditions that are subject to the reporting requirements of §191.23 of this subchapter.

(e) Surveillance, emergency response, and accident investigation. The procedures required by §§192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-59, 53 FR 24950, July 1, 1988; 53 FR 26560, July 13, 1988 Amdt. 192-71, 59 FR 6579, Feb. 11, 1994]

§192.607 Initial determination of class location and confirmation or establishment of maximum allowable operating pressure.

(a) Before April 15, 1971, each operator shall complete a study to determine for each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress that is more than 40% of SMYS:

(1) The present class location of all such pipeline in its system; and

(2) Whether the hoop stress corresponding to the maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

(b) Each segment of pipeline that has been determined under paragraph (a) of this section to have an established maximum allowable operating pressure producing a hoop stress that is not commensurate with the class location of the segment of pipeline and that is found to be in satisfactory condition, must have the maximum allowable operating pressure confirmed or revised in accordance with §192.611. The confirmation or revision must be completed not later than December 31, 1974.

(c) Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this section shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmations or revisions determined to be necessary under §192.609, to the extent that they are caused by changes in class locations taking place before July 1, 1973.

[35 FR 13257, Aug. 10, 1970, as amended by Amdt. 192-5, 36 FR 18194, Sept. 10, 1971]

§192.609 Change in class location: Required study.

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is more than 40% of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be ascertained from available records;

(d) The operating and maintenance history of the segment;

(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less

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than 8 hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72% of the SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of SMYS in Class 4 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(iii) The corresponding hoop stress may not exceed 72% of the SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of SMYS in Class 4 locations.

(b) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§192.553 and 192.555.

(c) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 18 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the 18-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

(Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. 1671 et seq.; Part 1, Regulations of the Office of the Secretary of Transportation, 49 CFR Part 1, delegation

of authority to the Director, Office of Pipeline Safety, November 6, 1968 (33 FR 16465) [35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-5, 36 FR 18195, Sept. 10, 1971; Amdt. 192-53, 51 FR 34988, October 1, 1986; Amdt. 192-63, 54 FR 24173, June 19, 1989]

§192.613 Continuing Surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).

§192.614 Damage prevention program.

(a) Except for pipelines listed in paragraph (c) of this section, each operator of a buried pipeline shall carry out in accordance with this section a written program to prevent damage to that pipeline by excavation activities. For the purpose of this section, "excavation activities" include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earth moving operations. An operator may perform any of the duties required by paragraph (b) of this section through participation in a public service program, such as a "one-call" system, but such participation does not relieve the operator of responsibility for compliance with this section.

(b) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who potentially engage in excavation activities in the area in which the pipeline is located.

(2) Provide for notification of the public in the vicinity of the pipeline and actual notification of

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the persons identified in paragraph (b)(1) of the following as often as needed to make them aware of the damage prevention program:

- (i) The program's existence and purpose;
- (ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, any inspection must include leakage surveys.

(c) A damage prevention program under this section is not required for the following pipelines:

- (1) Pipelines in a Class 1 or 2 location.
- (2) Pipelines in a Class 3 location defined by §192.5(d)(2) that are marked in accordance with §192.707.
- (3) Pipelines to which access is physically controlled by the operator.
- (4) Pipelines that are part of a petroleum gas system subject to §192.11 or part of a distribution system operated by a person in connection with that person's leasing of real property or by a condominium or cooperative association.

[Amdt. 192-40, 47 FR 13824, Apr. 1, 1982; Amdt. 192-57, 52 FR 32800, Aug. 31, 1987]

§192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

- (1) Receiving, identifying, and classifying

notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible.

(b) Each operator shall:

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

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(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

(d) Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

[Amdt. 192-24, 41 FR 13587, Mar. 31, 1976]

§192.616 Public Education

Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

[Amdt. 192-71, 59 FR 6579, Feb. 11, 1994]

§192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where

appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

§192.625 Odorization of gas.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50% of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975:

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction; or

(3) In the case of a lateral line which transports gas to a distribution center, at least 50% of the length of that line is in a Class 1 or Class 2 location.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section.

[35 FR 13257, Aug. 19, 1970 as amended by 36 FR 19168, Dec. 31, 1971, Amdt. 192-7, 37 FR 17970, Sept. 2, 1972, Amdt. 192-14, 38 FR 14943, June 7, 1973, Amdt. 192-15, 38 FR 35471, Dec. 28, 1973, Amdt. 192-16, 39 FR 45253, Dec. 31, 1974, Amdt. 192-21, 40 FR 20279, May 9, 1975]

Subpart M - Maintenance

§192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

§192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Class	Maximum interval between patrols	
	At highway and railroad crossings	At all other places
1,2	7 1/2 months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4 1/2 months; but at least four times each calendar year.	7 1/2 months; but at least twice each calendar year.
4	4 1/2 months; but at least four times each calendar year.	4 1/2 months; but at least four times each calendar year.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as

amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982.]

§192.706 Transmission lines: Leakage surveys.

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted--

(a) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year; and

(b) In Class 4 locations, at intervals not exceeding 4 1/2 months, but at least four times each calendar year.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§192.707 Line markers for mains and transmission lines.

(a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

(b) Exceptions for buried pipelines. Line markers are not required for buried mains and transmission lines--

(1) Located offshore or at crossing of or under waterways and other bodies of water; or

(2) In Class 3 or Class 4 locations--

(i) Where placement of a marker is impractical; or

(ii) Where a damage prevention program is in effect under §192.614.

(c) Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) Marker warning. The following must be written legibly on a background of sharply con-

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trasting color on each line marker:

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with one-quarter inch stroke.

(2) The name of the operator and telephone number (including area code) where the operator can be reached at all times.

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1672); sec. 1.58(d) of the regulations of the Office of the Secretary of Transportation (49 CFR 1.58(d)), and the redelegation of authority to the Director, Office of Pipeline Safety, set forth in Appendix A to Part 1 of the regulations of the Office of the Secretary of Transportation (49 CFR Part 1), 1.53(a)).

[Amdt. 192-20, 40 FR 13505, Mar. 27, 1975; Amdt. 192-27, 41 FR 39752, Sept. 16, 1976, as amended by Amdt. 192-20A, 41 FR 56808, Dec. 30, 1976; Amdt. 192-44, 48 FR 25208, June 6, 1983]

§192.709 Transmission lines: Record keeping.

Each operator shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service.

§192.711 Transmission lines: General requirements for repair procedures.

(a) Each operator shall take immediate temporary measures to protect the public whenever:

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40% of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery. As soon as feasible the operator shall make permanent repairs.

(b) Except as provided in §192.717(a)(3), no operator may use a welded patch as a means of repair.

(49 U.S.C. 1672, 1804; 49 CFR 1.53, Appendix A of Part 1 and Appendix A of Part 106) [35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27B, 45 FR 3274, Jan. 17, 1980]

§192.745 Valve maintenance: Transmission lines.

Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15-months, but at least once each calendar year.

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

Subpart C - Adoption of One-Call Damage Prevention Program

- 198.31 Scope.
- 198.33 (Reserved)
- 198.35 Grants conditioned on adoption of one-call damage prevention program.
- 198.37 State one-call damage prevention program.
- 198.39 Qualifications for operation of one-call notification system.

Authority: 49 App. U.S.C. 1674, 1687 and 2004; 49 CFR 1.53.

Subpart A - General

§198.1 Scope.

This part prescribes regulations governing grants-in-aid for State pipeline safety compliance programs.

§198.3 Definitions

As used in this part:

Adopt means establish under State law by statute, regulation, license, certification, order, or any combination of these legal means.

Excavation activity means an excavation activity defined in §192.614(a) of this chapter, other than a specific activity the State determines would not be expected to cause physical damage to underground facilities.

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Excavator means any person intending to engage in an excavation activity.

One-Call notification system means a communication system that qualifies under this part and the one-call damage prevention program of the State concerned in which an operational center receives notices from excavators of intended excavation activities and transmits the notices to operators of underground pipeline facilities and other underground facilities that participate in the system.

Person means any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

Underground pipeline facilities means buried pipeline facilities used in the transportation of gas subject to the Natural Gas Pipeline Safety Act of 1968 (49 App. U.S.C. 1671 et seq.) or the transportation of a hazardous liquid subject to the Hazardous Liquid Pipeline Safety Act of 1979 (49 App. U.S.C. 2001 et seq.).

Secretary means the Secretary of Transportation or any person to whom the Secretary of Transportation has delegated authority in the matter concerned.

Seeking to adopt means actively and effectively proceeding toward adoption.

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Subpart C - Adoption of One-call Damage Prevention Program

§198.31 Scope

This subpart implements section 20 of the Natural Gas Pipeline Safety Act of 1968 (49 App. U.S.C. 1687), which directs the Secretary to require each State to adopt a one-call damage prevention program as a condition to receiving a full grant-in-aid

for its pipeline safety compliance program.

§198.33 (Reserved)

§198.35 Grants conditioned on adoption of one-call damage prevention program.

In allocating grants to State agencies under section 5 of the Natural Gas Pipeline Safety Act of 1968 (49 App. U.S.C. 1674) and under section 205 of the Hazardous Liquid Pipeline Safety Act of 1979 (49 App. U.S.C. 2004), the Secretary considers whether a State has adopted or is seeking to adopt a one-call damage prevention program in accordance with §198.37. If a State has not adopted or is not seeking to adopt such program, the State agency may not receive the full reimbursement to which it would otherwise be entitled.

§198.37 State one-call damage prevention program.

A State must adopt a one-call damage prevention program that requires each of the following at a minimum:

(a) Each area of the State that contains underground pipeline facilities must be covered by a one-call notification system.

(b) Each one-call notification system must be operated in accordance with §198.39.

(c) Excavators must be required to notify the operational center of the one-call notification system that covers the area of each intended excavation activity and provide the following information:

(1) Name of the person notifying the system.

(2) Name, address and telephone number of the excavator.

(3) Specific location, starting date, and description of the intended excavation activity.

However, an excavator must be allowed to begin an excavation activity in an emergency but, in doing so, required to notify the operational center at the earliest practicable moment.

(d) The State must determine whether telephonic and other communications to the operational center of a one-call notification system under paragraph (c) of this section are to be toll free or not.

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(e) Except with respect to interstate transmission facilities as defined in section 2 of the Natural Gas Pipeline Safety Act of 1968, 49 App. U.S.C. 1671, and interstate pipelines as defined in §195.2 of this chapter, operators of underground pipeline facilities must be required to participate in the one-call notification systems that cover the areas of the State in which those pipeline facilities are located.

(f) Operators of underground pipeline facilities participating in the one-call notification systems must be required to respond in the manner prescribed by §192.614(b)(4) through (b)(6) of this chapter to notices of intended excavation activity received from the operational center of a one-call notification system.

(g) Persons who operate one-call notification systems or operators of underground pipeline facilities participating or required to participate in the one-call notification systems must be required to notify the public and known excavators in the manner prescribed by §192.614(b)(1) and (b)(2) of this chapter of the availability and use of one-call notification systems to locate underground pipeline facilities. However, this paragraph does not apply to persons (including operator's master meters) whose primary activity does not include the production, transportation or marketing of gas or hazardous liquids.

(h) Operators of underground pipeline facilities (other than operators of interstate transmission facilities as defined in section 2 of the Natural Gas Pipeline Safety Act of 1968, 49 App. U.S.C. 1671, and interstate pipelines as defined in § 195.2 of this chapter), excavators, and persons who operate one-call notification systems who violate the applicable requirements of this subpart must be subject to civil penalties and injunctive relief that are substantially the same as are provided under sections 11 and 12 of the Natural Gas Pipeline Safety Act of 1968 (49 App. U.S.C. 1679a and 1679b).

§198.39 Qualifications for operation of one-call notification system.

A one-call notification system qualifies to operate under this subpart if it complies with the following:

(a) It is operated by one or more of the following:

(1) A person who operates underground pipeline facilities or other underground facilities.

(2) A private contractor.

(3) A State or local government agency.

(4) A person who is otherwise eligible under State law to operate a one-call notification system.

(b) It receives and records information from excavators about intended excavation activities.

(c) It promptly transmits to the appropriate operators of underground pipeline facilities the information received from excavators about intended excavation activities.

(d) It maintains a record of each notice of intent to engage in an excavation activity for the minimum time set by the State or, in the absence of such time, for the time specified in the applicable State statute of limitations of tort actions.

(e) It tells persons giving notice of an intent to engage in an excavation activity the names of participating operators of underground pipeline facilities to whom the notice will be transmitted.

**APPENDIX D
RESULTS OF 1994 INTERNAL INSPECTIONS OF LINE 20**

1994 Magnetic-flux Inspection

Location (MP to MP)	Grade and Percent of Metal Loss					Possible Dents
	1 20 to 30%	2 30 to 40%	3 40 to 50%	4 50 to 60%	5 60 to 100%	
0.00 to 6.10	0	0	0	0	0	0
6.10 to 12.81	0	0	0	0	0	8
12.87 to 18.96	0	0	0	0	0	0
18.96 to 19.85	0	0	0	0	0	0
19.85 to 23.70	0	0	0	0	0	0
23.70 to 24.20	0	0	0	0	0	0
24.20 to 29.60	0	0	0	0	0	1
29.60 to 35.00	0	0	0	0	0	2
35.00 to 39.70	0	0	0	0	0	0
39.70 to 40.20	0	0	0	0	0	1
Total	0	0	0	0	0	12

1994 Inertial Geometry Inspection

Location (MP to MP)	Number of Deviations	Largest Percent of Deviation	Number of Dents
0.00 to 6.10	20	1.8	0
6.10 to 12.81	34	3.8	2
12.87 to 18.96	15	1.8	0
18.96 to 19.85	2	1.3	0
19.85 to 23.70	5	1.2	0
23.70 to 24.20	3	1.5	0
24.20 to 29.60	44	2.9	0
29.60 to 35.00	10	1.4	0
35.00 to 39.70	4	1.3	0
39.70 to 40.20	1	0.0	0
Total	138		

APPENDIX E

EXCAVATION DAMAGE PREVENTION WORKSHOP FINDINGS

For the workshop jointly sponsored by the Safety Board and DOT/RSPA, four work groups addressed issue areas important for preventing excavation-caused damage to pipelines. Each work group had a facilitator experienced in leading panel discussions and about 20 representatives from communication, electric, water/sewer, pipelines, excavators, Federal government, State government, notice centers and others. The remaining workshop participants could observe any one or all of the work groups and provide their input to the discussions on the various subjects. The panels were allowed to develop their dialogues and consensus findings using the format of their choosing. The panel results follow.

GROUP 1 - What are the essential elements of effective one-call notification systems?

Definition: A one-call notification system is a communication system established by two or more underground network owners or operators to provide one telephone number for excavators, be they contractors, homeowners, utilities, public agencies, or others, to call for notification of their intent to use equipment for excavating, tunnelling, demolition, or otherwise disturbing the subsurface of the earth. This below-ground protection system provides participating members an opportunity to identify and mark their facilities in the vicinity of proposed activity. The notification also allows the owners of underground facilities to provide any necessary information about the facilities and to post a construction watch, if desired.

Must have:

- * All owners of buried facilities shall register their facilities except those owners of private facilities restricted to their property and their use.
- * All members of the digging community shall use the service.
- * Pro-active public awareness, education and damage prevention activities incorporating a broad spectrum of available opportunities.
- * Specifically defined geo-political service area with no over-lap.
- * Toll free access nationwide.
- * Hours of full operation compatible with digging community with provision for 24-hour access to the system.
- * Voice Record of all incoming calls.
- * Retention of voice tapes according to applicable statutes.
- * Provide and advise caller of ticket number for each locate request, and the names of facility owners who will be notified.
- * Be able to provide a printed copy of any ticket for a period of time determined by any statute of limitations.
- * Provide timely transmission of notifications to facility owners.
- * Be able to provide regular statistical, financial and administrative reports.
- * Allow input to operational procedures from facility owners and digging community.
- * Documented operating procedures, human resources policies, and training manuals

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- * User friendly for entire digging community.
- * Cost effective.
- * Promote recognition, awareness, and acceptance of the responsibilities of facility owners and digging community, including a users guide.
- * Formal agreements with members.
- * Documented owner verification of data submitted by facility owners.
- * Sufficient flexibility to incorporate local requirements.
- * Computer/communications systems sufficiently flexible to accommodate growth and change.
- * Accept and process locate requests placed within the locally accepted advance notice period.
- * Advise callers of any limitations on service or system.
- * Accept and process short notice, priority and emergency locate requests.

Should have:

- * No cost to users of the system.
- * Contingency plan
- * Foster cooperation and enhance relationships between digging community and facility owners, including developing a means of communicating the owner response to the excavator.
- * Regular communications with customers.
- * Determine and maintain quality of telephone service factors acceptable to system users.
- * Employ mechanisms to reduce over-notification.
- * Governed by non-profit corporation.
- * Capability of tracking the origin or locate requests by various criteria -member, contractor, homeowner, municipality.
- * Cooperative working relationships with agencies and associations with mutual areas of interest or concern, including membership in OCSI and active participation in utility coordination and damage prevention committees.
- * Pro-active management.
- * Machine-readable notifications.
- * Toll-free fax access.

Could have:

- * 24-hour staffed operation.
- * Accept and process locate requests for design purposes.
- * Management of damage incident database.
- * Facilitate appointment plan.
- * Addition of aerial facilities.
- * Do locating on contract basis.
- * Provision for "no locate required".
- * Cellular "Star" number for no-charge access.
- * Remote entry by major users.
- * "Interactive voice" tracking of locate status - positive response.

GROUP 2 - What responsibilities should buried facility operators have?

Should the American Public Works Associations' *Guidelines for Uniform Temporary Markings of Underground Facilities* continue to be the recognized marking code?

- * Uniform Color Code should be used to temporarily mark facilities.
- * Markings should include facility owner identification.

What responsibilities should buried facility operators have?

- * Buried facility operators should advise excavators/contractors when marking can't be performed in compliance with normal state time frame or make a reasonable attempt to advise excavator/contractor when operator has no facilities in area?
 - Partnership approach.
 - Positive response not required for ALL situations.

How?

- * Telephone/fax/cellular phone/means by which contractor supplies. (voice mail?)
- * One-call as conduit.

What should the optimum/minimum response times for marking facilities be?

- * No one size fits all.
- * No decision reached on this question.

What accuracy standard should be used for operator marking?

- * Need understanding of "tolerance zone".
- * Use standards as they exist along with tolerance zone education.

What coordination/communications with excavators should operators have relative to excavation precautions and emergency notifications?

- * Provide information to known emergency services, to include anticipated response times.
- * Have established procedures for emergency notification.

Should depth of facility be provided?

- * NO.

What role should buried facility operators have for educating excavators/contractors/public on use of one-call and working safely adjacent to buried facilities?

- * One-call programs should have systematic programs to promote use & function of system: statewide and national.
- * Additional educational efforts by individual operators should support the one-call program and also provide facility-specific education.
(Contractor/contractor associations/insurance companies should share in responsibility of training employees.)
- * Mechanism to ensure message is received by public & encourage feedback (program effectiveness analysis).
- * Any campaign advertising one-call should be coordinated with appropriate one-call facility.

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Working adjacent to buried facilities

- * Facility owners take responsibility for the education of their employees & subcontractors.

What type marking equipment should be used?

- * Use clearly identifiable materials appropriate to environment and conditions.

When excavation show errors in mapping information, should operators be required to update maps?

- * YES.

What facility owners should be in the one-call system?

- * All owners/operators should be full participating members in a one-call system.

Which buried facility owners/operators should participate in damage prevention?

- * Any buried facility owner should be involved in a damage prevention program.

What actions should operators take for long-term projects?

- * Advance and continuing coordination with documentation between operators and excavators (such as temporary markings).
- * Follow-up reports/communications between company and excavator.
- * Support and attend preconstruction meetings for major projects.
- * The need may exist for excavators to update ticket through one-call.

How will customer-owned services lines get marked?

How will yard lines get marked?

- * Facility owners should accept responsibility for marking up to a predetermined point, such as a meter, an interface device, and so forth.
- * [CT state statute allows utilities to mark out customer-owned service lines with a hashed/broken mark which avoids liability for the utility, but allows for a best guess locate of a facility they are not responsible for.]
[Locate if locatable...no liability?]
[Pool heaters/gas grills/gas lamps? Educate homeowner/public.]

How will abandoned Facilities get marked?

- * As a best practice, utilities should be encouraged to maintain future abandoned facilities on facility records.

Standardized markings at time of installation? [Can provide additional liability protection.]

Excavator Premarking.

- * Encourage white line marking where applicable and practicable.
- * To improve communications and efficiencies in facilities markings, we encourage the use of white-lining proposed excavations.
- * Extensive excavation plans should be submitted.
- * If premarking is not used, it is the excavator's responsibility to clearly and adequately identify the area of the intended excavation.

GROUP 3 - What responsibilities should excavators have?

Which excavators should be required to notify the one call system?

- * The panel recommends that no excavators be exempted from calling the one-call system.

Should the area to be excavated be pre-marked by the excavator before owners mark their facilities?

- * Pre-marking the proposed excavation areas has been demonstrated to enhance the safety of excavation activities.

What damage to facilities should excavators report and to whom?

- * The panel recommends that any contact or other activity which impacts the integrity of an underground facility be reported.
- * Reports should be made to the owner, operator and/or one-call system.

How should excavators determine the depth of buried facilities?

- * The panel recommends that excavators use non-mechanized hand tools or tools specifically designed to safely expose an underground facility to determine its exact location. The panel further recommends that excavators and underground facility owners work together to develop installation standards and new depth location technology.

What operation of machinery should be permitted in marked areas? Under what circumstances?

- * The panel recommends that the operation of excavation machinery be permitted in marked areas as required or necessary once the underground facility is exposed and adequately protected.

What role should excavator associations have in educating excavators, equipment operators and the public in working safely adjacent to buried facilities?

- * The panel recommends that excavator associations work in conjunction with facility owners, operators and one-call systems to include underground facility damage prevention training as part of safety training.

What actions must excavators take to protect underground facilities?

- * The panel recommends that excavators take any and all prudent and reasonable steps necessary to protect the integrity of the underground facility in cooperation with facility owners and operators.

Should excavators be required to advise the center as to length of time for completing the reported project?

- * The panel recommends that excavators notify the one-call centers as to the approximate length of time for the project.

Should there be a time limit on the validity of the ticket issued by the one-call center?

Appendix C

- * The panel recommends that state laws and regulations define starting times and lengths of time when tickets are valid.

Other recommendations:

- * The panel recommends that the standardized color code be limited to the marking of underground facilities at the job site.
The panel further recommends that the ULCC look at developing other color codes for additional circumstances.

GROUP 4 - How should the damage prevention program be administered?

Federal role in damage prevention

- * Set minimum guidelines and encourage standards that a State may set in conformance with national guidelines.
- * Determine what went wrong and how do we fix it.
- * Promote technology transfer.
- * Comprehensive participation driven by Federal law.

Local and State role in damage prevention

- * Monitor the levels of construction activity and damage occurrence
 1. To measure effectiveness
 2. To target need for improvement
- * Damage going down with construction increasing
- * Mandatory participation
 1. Facility operator
 - Federal-
 - State-
 - local-
 2. Excavator
 - Federal-
 - State-
 - local-

Enforcement

- * Self policing partnerships
- * Enforcing penalties, ability to recover costs
- * Specific Agency responsibility for authority

Education

- * An equal partnership between facility owners and the contractors
 - a. Targets of education
 1. People moving the earth
 2. Locators
 3. Public

4. Survey organizations
5. Regulatory authorities
6. Engineers and Designers
7. Zoning and Siting Boards
8. Attorneys, Legislators, and Judges
- b. Format of educational objectives
 1. Training
 2. Awareness
 3. Benefits of using one-call for
 - a. Engineers and designers
 - b. Contractors
 4. Safety and responsibility
 5. Penalties and liability
 6. Emergency response
- c. Methods

Positive incentives

- a. Enhanced personal safety at the work site
- b. Cost effective to the excavator and facility owner
- c. Insurance discounts for damage prevention programs
- d. Reduce liability for self reporting (NEB)
- e. Preserving our infrastructure
- f. Pre-marking sites of proposed construction
- g. Protecting the environment

Where is the data?

- a. Facility owners (may or may not report)
- b. Insurance
- c. Associations
- d. One-Call operation

Concerns of Group:

- * Universal participation
 1. Define minimum risk which requires level of participation in the program within each state
 2. Flexibility for alternative procedures that meet the spirit and intent of the program by mutual agreement of excavator and operator on a case-by-case basis.
- * Create positive incentives for damage prevention programs.
- * Educate all stakeholders
- * Establish clearly defined Federal, State, and local roles.
- * Ensure membership control of One-Call Centers.
- * Retain the strength of current damage prevention programs

Appendix C

- * Courage to continue
- * Establish, publish, and distribute procedures for dealing with violations and funding.
- * Requirements of the damage prevention program are balanced for:
 1. Facility owner
 2. Excavator
- * Team work to solve problems
- * Practical Considerations
 1. Remember that law affects all areas of the country
 2. Administration of program will be as simple and as streamlined as possible with a minimum of government oversight
 3. Sensitive to cost impacts for all stakeholders
- * Why do damages continue to occur even when comprehensive programs are in place?
 1. Recommend further research to accomplish continuous improvements.
 2. On-going data gathering system, such as data tracking
- * Geographic boundaries will decide who has responsibility over interstate facilities.
- * Encourage competency reviews for owners and excavators.
- * Write rules in a way that encourages creativity.
- * Require single one-call systems in each geographic area.
- * Establish criteria in order that new underground facilities can be located without excavation.