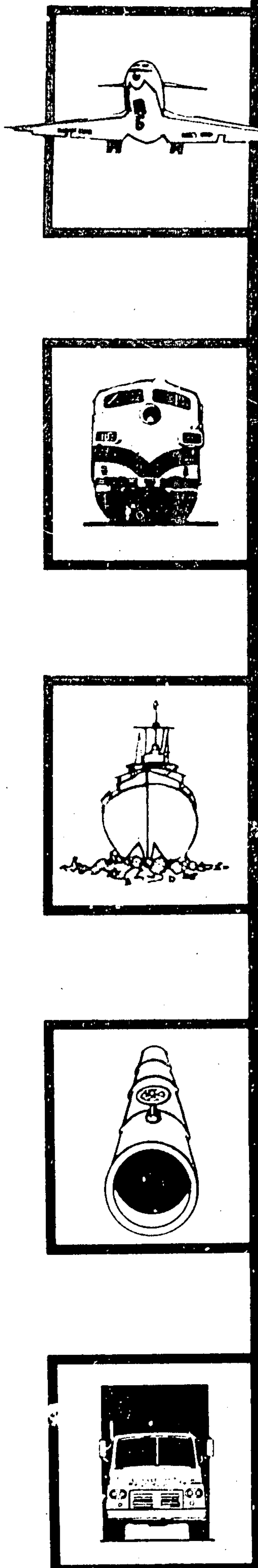

PB86-916502

NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT/INCIDENT SUMMARY REPORTS

JACKSON, LOUISIANA - - NOVEMBER 25, 1984

PINSON, ALABAMA - - AUGUST 22, 1985

NTSB/PAR-86/01/SUM

UNITED STATES GOVERNMENT

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This publication is a compilation of the reports of two separate pipeline accidents investigated by the National Transportation Safety Board. The accident locations and dates are Jacksonville, Louisiana, November 25, 1984, and Pinson, Alabama, August 22, 1985.

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CONTENTS

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PIPELINE ACCIDENT/INCIDENT SUMMARY

Pipeline Accident No.:	DCA-85-FP-003
Location;	Jackson, Louisiana
Date:	November 25, 1984
Time:	1300 Central Standard Time
Owner/Operator:	Texas Eastern Gas Pipeline Company
Property Damage:	$870,000
Injuries:	5 fatal; 23 nonfatal

About 1300 1/ on November 25, 1984, Texas Eastern Gas Pipeline Company's (Texas Eastern) 30-inch-diameter natural gas transmission pipeline, constructed in 1955 and operating at 1,000 psig pressure, ruptured at a location about three miles west of Jackson, Louisiana. Gas blowing from the rupture fractured the pipe into many pieces and created a hole in the earth about 90 feet long, 25 feet wide, and 10 feet deep. The escaping gas was quickly ignited by one of several potential sources of ignition (construction equipment engines, static electricity, sparks resulting from debris blown from the pipeline, etc.). The resulting fire incinerated an area extending from the rupture about 950 feet north, 500 feet south, and 180 feet to the east and to the west. Within this sparsely populated area, five persons involved with the pipeline construction work were killed and 23 persons, construction workers and public, were injured. Additionally, several pieces of construction equipment were damaged extensively. Of the injured persons, most were located about 800 feet north of the rupture within a hunting club facility that included 11 trailers or campers also destroyed by fire.

About two minutes after the explosion, Texas Eastern closed the valves at its Saint Francisville compressor station located three miles south of the rupture, and at 1303 a citizen notified the St. Francisville Fire Department (SFFD) of the accident. The Jackson Volunteer Fire Department (JVFD) arrived at 1314, reporting that a column of flame was rising several hundred feet into the air and that heat from the flame was too intense for emergency response personnel to approach the area of the rupture. Units from the SFFD, the West Feliciana Parish Sheriff's Office (WFPSO), and the Louisiana State Police arrived soon after. When the WFPSO Sheriff arrived at 1320 he took command of the emergency, established a command post to serve as a staging area for all responding emergency units, and denied access to the area for persons not essential to the emergency response activities. Law enforcement personnel evacuated residents from the immediate area without incident. When the pipeline segment containing the rupture was isolated from the gas supply, the intensity of the flames receded rapidly until, for lack of fuel, the fire was extinguished.

A May 18, 1984, survey performed by Texas Eastern, determined that the population density along a one-mile segment of the pipeline had increased as a result of additions to a hunting club facility and the installation of mobile homes on adjacent property. As a result, a higher internal pipe pressure design safety factor was necessary to comply with federal safety requirements (49 CFR 192). To accomplish the required improvements, Texas Eastern contracted with Clarkco Construction, a private pipeline construction

1/ All times are based on the 24-hour clock and are reported in central standard time.

company, to replace 1,500-foot segments of its two parallel pipelines in this area. This work required removing a pipe segment from each of the existing pipelines (pipe in both segments manufactured to American Petroleum Institute ,API. standards for X-52 pipe); constructing new, stronger, and thicker pipe segments (API X-65) offset from the present pipeline route; testing the new pipeline segments; isolating, cutting, and purging the existing pipeline segments to be removed; and connecting the new pipeline segments to the existing pipelines.

After the new pipeline segments were constructed and hydrostatically tested, on November 24, 1984 the contractor was ready to connect the new 30-inch pipeline segment to the existing 30-inch pipeline. To weld the new pipeline segment to the existing pipeline, the ends of the pipes were lifted 4 to 5 feet above the original elevation of the existing pipeline. This task required excavating a 40-foot segment of the existing pipeline adjacent to the area where the weld connection was to be made. After the connecting weld was completed, the lifting forces on the pipe were removed; however, the connected pipe segments remained about two feet above the original elevation of the existing pipeline at the weld connection. Several attempts were made by the contractor to lower the pipeline to its original elevation by removing soil from beneath pipe segments adjacent to the weld connection, but when the lowering was not successful, the 2-foot gap between the ditch bottom and the pipe was filled with uncompacted soil. It was estimated that 75 - 100 feet of pipe was not supported from beneath by a properly compacted soil foundation.

After welding the new pipeline segment to the existing pipeline, construction equipment began filling excavations, the weld was x-ray inspected, and the pipeline was purged of water and air. At 0100 on November 25, 1984, gas under pressure was flowed into the pipeline segment by opening a nearby valve until the pressure in the segment reached 700 psig. After the pressure in the segment stabilized, indicating the absence of a leak, the pressure in the segment was increased to the operating pressure of the pipeline, 1,016 psig., and the line was again placed in service. The backfill operations began on November 24, 1984 and were continued on November 25, 1984. Just before the rupture of the pipeline, contractor personnel were operating heavy equipment (backhoe and bulldozer) over the pipeline about 65 feet north and south of the final weld connection.

Texas Eastern's Specification No. P-6705, Backfilling, states that attention shall be given to ensure that a dirt cushion 1/ is placed around and under the pipe to completely fill all voids. In addition Paragraph 192.319 of 49 CFR 192 requires that when a ditch for a transmission line or main is backfilled, it must be backfilled to provide firm support under the pipe.

The pieces of the fractured pipeline recovered during the investigation were assembled and the fracture surfaces examined by metallurgists of the Safety Board and the Battelle Petroleum Technology Center at Houston, Texas. While all pieces of the pipe were not recovered, metallurgists determined that the recovered pieces included those where the fracture originated. These pieces were transported to Battelle's Houston, Texas facility for indepth examination and testing. The origin of the fracture was located on the bottom of the pipe at the final weld connection. The fracture origin was determined to be confined to the X-52 pipe segment of the existing pipeline (1955), located in an area where the X-52 and X-65 pipe segments were not fully in alignment.

1/ The term "dirt cushion" means the addition of noncompacted soil to fill voids adjacent to the pipeline.

The fracture began at the toe of the weld reinforcement on the outside of the pipe. The fracture origin was confined to the heat-affected zone. No weld defects were found at the origin, and no base metal defects that would have contributed to the failure were identified. All of the above work either was performed by Safety Board staff or was performed under the Board's supervision.

Review of the x-ray film, made soon after completion of the final connection weld but before the contractor, under the authority of the gas company, reintroduced gas under pressure into the pipeline, indicated that while the weld was not of the highest quality, it complied with API Standards 1104, Standard for Welding Pipe Lines and Related Facilities, 15th Edition. Compliance with this Standard was mandated by 49 CFR 192 and by Texas Eastern's Welding Procedure Specification Manual.

Metallurgical examination of the final weld connection revealed that the X-52 and X-65 pipe ends were misaligned vertically, with the X-52 pipe being displaced upward relative to the X-65 pipe. Further, the misalignment was not uniformly distributed around the circumference of the pipe connection. Moreover, additional misalignment was caused by the pipes being out-of-round. Although the pipe ends were not fully aligned, there was no lack of filling or lack of penetration of the weld in excess of that allowed by API Standard 1104; however, the misalignment between the pipe ends was not uniformly distributed as required by API Standard 1104.

The weld on the final connection of the new pipeline segment to the existing pipeline met applicable standards and was capable of withstanding without failure all stresses normally anticipated during the operation of a pipeline, as evidenced by the following facts: the x-ray of the weld made before the pipeline was subjected to pressure met the quality standards of API Standard 1104; the weld withstood without failure or leakage more than 1,000 psig for about 12 hours; and metallurgical tests performed after the rupture confirmed that, except for the misalignment not being uniformly spaced, the weld complied with applicable API Standard 1104 requirements.

The installation of the pipe in the ditch violated federal regulations since the backfill did not provide firm support under the pipe. This installation also did not comply with the gas industry's recommended practices as compiled in the American Society of Mechanical Engineer's "ASME Guide for Gas Transmission and Distribution Piping Systems." This guide recommends that, "On pipelines operating at stresses of 20 percent or more of specified minimum yield strength, it is important that stresses induced into the pipeline by construction be minimized. The pipe should fit the ditch without the use of external force to hold it in place until the backfill is completed." Texas Eastern's contractor and Texas Eastern's own inspection personnel failed to comply with the federal requirement to provide a firm support beneath the pipeline. In addition, they failed to follow recommended industry guidance for supporting the pipeline. As the heavy construction equipment working over the pipeline to complete the backfill operations approached the inadequately supported segment of pipeline, the weight of the construction equipment forced the pipeline downward, thereby increasing the level of stress in the pipe wall and weld. As the equipment worked nearer the final connection weld where a greater depth of uncompacted soil had been filled beneath the pipe, the stresses in the pipe wall increased beyond the stress carrying capability of the weld connection and the fracture initiated. The nonuniform spacing of the misalignment between the pipe ends most likely facilitated the initiation of the fracture; however, the fracture most likely would have initiated even had this point of stress concentration not been present.

Therefore, the National Transportation Safety Board recommends that the Texas Eastern Gas Pipeline Company:

> Revise its construction specifications to require that proper support be provided beneath gas pipelines when they are installed. (Class II, Priority Action) (P-86-01)

> Train its construction/inspection personnel in the revised backfill procedures and monitor periodically their inspection of pipeline construction projects to verify conformance with these procedures. (Class II, Priority Action) (P-86-02)

The National Transportation Safety Board determines that the probable cause of the accident was the failure of Texas Eastern Gas Pipeline Company to require compaction of the soil backfilled beneath the excavated pipeline before permitting heavy construction equipment to operate over the pipeline during the final backfill operations. Contributing to the extent of injuries and damage was the pipeline's proximity to inhabited buildings and the operation of the pipeline under high pressure before all work was complete.

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

/s/ JIM BURNETT
Chairman

/s/ PATRICIA A. GOLDMAN
Vice Chairman

/s/ JOHN K. LAUBER
Member

February 12, 1986

National Transportation Safety Board
Washington, D.C. 20594

PIPELINE ACCIDENT/INCIDENT SUMMARY

Pipeline Accident No.:	DCA-85-FP-018
Location:	Pinson, Alabama
Date:	August 22, 1985
Time:	10:50 a.m., c.s.t.
Owner/Operator:	Alabama Gas Company
Property Damage:	$1 million
Injuries:	6 nonfatal

On the morning of August 22, 1985, temperature gauges in the control room of the Alabama Gas Corporation (Alagasco) natural gas liquefaction plant in Pinson, Alabama, indicated that the third stage of the methane heat exchanger in the cold box 1/ was becoming restricted by frozen compressor oil. The accumulation of frozen compressor oil in the third stage of the methane heat exchanger is a routine occurrence because of the design of the compressor piston ring forced-feed lubrication system. When the excess oil that is moving with the methane encounters the cold temperatures of the third-stage heat exchanger it congeals and adheres to the heat exchanger. Upon instruction by the plant manager to defrost the third stage of the methane heat exchanger, the plant operator, with the help of two trainees, began to shut down the plant for defrosting. The steam boiler had been lit; the pressure in the liquid ethylene system had been reduced; the compressor had been blocked in by closing the discharge and suction valves; the plant feed gas valve had been closed; ethylene had been moved from the second and third stages to the first-stage heat exchanger and was being drained into storage; the ethylene, propane, and methane discharge valves had been closed; and the ethylene, propane, and methane suction valves had been closed. The plant operator and the two trainees were opening manually operated valves to drain liquid methane from the cold box into a vertical aluminum tank 3 feet in diameter and 7 feet tall (vessel 17.23A) when they heard a noise that sounded like a relief valve opening and felt the platform on which they were standing shake. One of the trainees saw an 8 1/4-inch by 12-inch aluminum plate that had been welded to vessel 17.23A being propelled through the air and strike a building 24 feet away which housed a control room, a boiler room, and offices. Some of the windows in the control room were blown inward, and methane escaping from the opening in vessel 17.23A entered the building.

The operator and two trainees then walked between vessel 17.23A and the building housing the control room to a door at the side which permitted entry into the boiler room. The plant manager and secretary who were in their offices and the contract groundskeeper who was in the control room joined them at this location. Shortly thereafter, the released methane was ignited and fire engulfed the control room and the area between the control room and vessel 17.23A. Two employees received critical burns, two received serious burns, and two received minor burns. Damage to the plant was estimated to be more than $1 million.

The plant manager assisted the contract groundskeeper in removing the secretary from the area, and then, because the fire had destroyed the plant telephone system, the plant manager went to a nearby manufacturing plant where he asked someone to telephone the Birmingham, Alabama Fire Department. Meanwhile, the contract groundskeeper attempted to use a large mobile fire extinguisher but was unable to cause it to discharge; he had not been trained to use the extinguisher. Tarrant and Center

1/ A cold box consists of heat exchangers, separators, vessels, and associated piping, all of which are enclosed in an insulated shell.

Point, Alabama Fire Departments also were notified; firefighters and paramedics responded and were met at the gate by the plant operator. The firefighters extinguished the fire in the control room, the fire on the side of the cold box, and after the methane drains were closed, the fire at the base of vessel 17.23A. All fires were extinguished about 11:50 a.m. the day of the accident. Four of the six injured Alagasco employees were taken by private automobile to a hospital in Birmingham before the emergency response personnel arrived. The other two injured employees were treated and transported to a hospital by the emergency response personnel.

The local fire department personnel were aware of the hazards posed by the gas and chemicals located at the facility because they had been briefed by Alabama Public Service Commission personnel and had toured the facility on several occasions in their familiarization training.

A Halon fire extinguishing system in the control room did not activate automatically as it was designed to do when the fire occurred. A 20-second delay was incorporated in the Halon system to allow an operator time to override the automatic discharge of the Halon in case the system was activated unnecessarily for some reason. Overriding the system would eliminate the need to replace the expensive Halon. The investigation revealed that the automatic controls of the Halon system were destroyed by the fire before the 20-second delay built into the system elapsed, thereby preventing the system from discharging. This Halon system was installed to protect the control panel from electrical fires originating in the enclosed control room; however, in this accident the windows were blown out of the control room and the methane fire, in the now open control room, would have been far too intense for the Halon system to suppress.

The Alagasco natural gas liquefaction plant at Pinson converts natural gas into liquid methane during periods when gas demand in the distribution system is low and stores the liquid methane until it is needed during peak demand periods. This peakshaving facility consists of four basic processes: gas treatment, liquefaction, storage, and vaporization. The accident occurred in the liquefaction plant.

According to Alagasco officials the Pinson plant, constructed by Alagasco and Air Products and Chemicals Incorporated (APCI) on a 315-acre plot of land near Birmingham, is the oldest operating natural gas liquefaction plant of this type in the nation. Alagasco owned the storage and vaporization processes; APCI owned the liquefaction process and was contracted by Alagasco to operate the entire facility when it first opened. The facility was originally designed to liquefy 3.9 million cubic feet of gas a day, and when needed, to return 127.5 million cubic feet of gas a day to the distribution system through three vaporizers. The facility initially had one storage tank with a capacity of 175,000 barrels. In 1969, a second storage tank was constructed to bring the storage capacity to 350,000 barrels and the fourth vaporizer was added. These additions allowed the facility to provide 227.67 million cubic feet of gas a day to the distribution system.

In 1971, Alagasco built a similar facility at Coosada, a small community near Montgomery, Alabama. The Coosada facility can liquefy 2.7 million cubic feet of gas a day, has the capability of returning 80 million cubic feet of gas a day to the distribution system through two vaporizers, and has one storage tank with a capacity of 175,000 barrels of liquefied natural gas.

On October 1, 1981, Alagasco purchased APCI's portion of the Pinson facility and took over its operation; some of the personnel who had been employed by ACPI remained at the facility as Alagasco employees. Since October 1, 1981, Alagasco has spent approximately $2 million renovating the Pinson facility.

When the plant was constructed in 1965, vessel 17.23A had an internal steam heating element. The senior operator stated that the element was removed from vessel 17.23A about 1975. He said that before the element was removed, the drain valves on the cold box that drain into vessel 17.23A were opened all at once to determine if it was possible to force liquid out the top of the flare vent stack, which was located near the control room next to the cooling tower. During this test, vessel 17.23A received a greater amount of cryogenic liquids and gases than it did on the day of the accident without showing any visible signs of stress. As a result of the test, the element was removed from vessel 17.23A by cutting a 6 7/8-inch by 9 3/4-inch hole into its base, and the aluminum plate that later failed during the accident was welded over the opening. An ambient temperature vaporizer was installed downstream of vessel 17.23A to replace the element, and the flare vent stack was moved to a remote area of the plant near the storage tanks.

Liquid methane has a temperature of approximately minus 260 degrees F, and when converted to a gaseous state each cubic foot of liquid provides 618 cubic feet of gas. In this accident, when the liquid methane initially entered vessel 17.23A, the vessel was at ambient temperature. When the cold liquid came in contact with the relatively warm vessel, it immediately began to vaporize, thereby increasing the pressure in vessel 17.23A. The investigation revealed that the noise heard by the employees and likened to that of a relief valve opening was caused by the separation of a 1-inch-diameter plastic hose that was being used as a substitute for a metal pipe connection to couple two pieces of 1-inch-diameter copper pipe. When the aluminum plate failed on vessel 17.23A, vessel 17.23A was propelled back about 3 inches into the platform on which the operator and the two trainees were standing, causing the platform to shake.

An operator of the plant stated that on June 25, 1985, he observed a leak of material from vessel 17.23A around the plate and entered his observation in the plant logbook. The assistant plant manager acknowledged this entry in the logbook. The assistant plant manager stated that because of the logbook entry a contractor had been contacted and had visited the plant to provide the company with an estimate for repairing or replacing the vessel with a stainless steel tank. The contractor provided to the Safety Board a copy of his estimate dated August 21, 1985. Title 49 CFR 193.2603(a) and (b) require that each component in service, including its support system, be maintained in a condition that is compatible with its operational or safety purpose by repair, replacement, or other means, and that an operator not place, return, or continue in service any component that is not maintained in accordance with this subpart. Therefore, the plant operator in this instance should not have continued this vessel in service.

During the investigation, three current plant operators, two trainees, and a previous plant manager were interviewed to learn of the procedures they would use in performing a similar defrost operation. All but one person had to refer to the engineering flowsheet for locating the valves to be operated; the other visually traced each external pipe to locate the control valve. None used the operating manual which identifies for each operation the valve to be operated and the sequence of operation. No two persons operated the valves in the same sequence. The one operator who did not use the engineering flowsheet often referred to it when asked specific questions. The former plant manager stated that failure to operate the plant in the prescribed manner could damage the equipment and create unsafe conditions. The engineering flowsheet had not been kept current. A 4-inch-diameter pipe connecting the exhaust of several relief valves to vessel 17.23A was not shown on the flowsheet, and the piping from which the plastic hose separated during this accident was not shown on the flowsheet as entering the header between the cold box and vessel 17.23A.

A postaccident inspection of the plant revealed many deficient maintenance conditions. At one point in time a numbered tag had been attached to each valve which conformed with an engineering flowsheet used by plant operators. Some of these tags were missing at the time of the accident, and many valve tags as well as gauges could not be read because paint obscured the numbers and gauge dials. Some of the gauges had glass missing or broken, some had the back cover missing, and some were deteriorated due to the glass not being in place. Liquid was found trapped between some of the glass coverplates and gauge dials, which made them difficult to read. Electrical junction boxes within the plant were open, exposing the wiring to the weather and to flammable gases. Some valve handles were missing, and their stems showed indications of having been operated by pipe wrenches. Covers for some electrical control panels in the building housing the control room and in another building housing the auxiliary generator control room were not positioned properly to enclose the panels, and they appeared to have been open quite some time before this accident.

During a normal work week, the day shift at the Pinson plant consists of six persons. The evening, night, and weekend day shifts are staffed with only one person. When there is only one person at the facility, that person is required to make hourly reports by telephone to Alagasco's North Birmingham Station and to wear a radio transmitter which, when activated, generates a tone at Alagasco's North Birmingham Station. When this tone is received, the North Birmingham Station personnel notify by telephone the persons on a call list, and those notified are to report to the plant. Should the North Birmingham Station fail to receive hourly a call from the plant operator, station personnel will first call the plant. If there is no answer at the plant, persons on an emergency notification listing of company personnel and emergency response agencies are next called. The first person on the list to answer the call is required to go to the plant to determine the reason for the failure of the plant operator to answer the telephone and to take any necessary emergency action.

Alagasco has an emergency procedures manual and its stated purpose is to provide a plan of action to control potential emergencies which may arise at the Pinson facility; however, a note in the manual indicates that the manual was designed for use in training and not for use during an emergency. The plan lists potential sources of emergencies such as derailments, chemical spills, and liquid natural gas spills in the liquefaction plant area as well as other locations. The actions to be taken in the event of liquid spills or gas leaks are listed in the manual under two categories--minor and major; however, the manual does not tell the user the difference between minor and major leaks or spills. The manual states that there is always potential for a fire under these conditions due to the flammability of the gases at the plant. Actions listed in the manual that are to be taken in the event of leakage range from total plant shutdown for a major leakage to repairing minor leakage. In the manual under the headings major emergency and major leakage, the first action listed instructs the user of the manual to break the glass and pull the lever on the ADT Security Systems alarm. The ADT alarm was not retained when Alagasco purchased APCI's holdings at the plant, yet some of the references to the ADT system have not been struck from the manual. The only action taken was to enter the information concerning the leaking vessel into the logbook of daily activities which was maintained in the control room and read daily by the plant manager or assistant plant manager. The procedures for using the leaking vessel were not changed nor was the vessel repaired or removed from service. (See appendix A.)

The fire system includes smoke detectors, ultraviolet monitors, television cameras, and automatic and manual alarms; however, none of these is designed to transmit the alarm outside the facility. The emergency manual states that the primary assembly point will be the control room and the alternate location is the main gate. In this accident everyone assembled near the control room, not to plan a course of action but to observe the damage. The manual places emphasis on the employees mitigating the emergency and, "time permitting," calling the fire department. The manual instructs the personnel, in the event of an emergency, to notify Alagasco personnel in the order of listing and the remaining listing of persons and emergency agencies as the situation warrants. While parts of the manual are out of date in that they contain references to obsolete practices, the listing of personnel to call had been updated earlier in 1985. Other changes to the manual include the deletion of references to APCI.

New employees who are to become operators of the plant receive 1 week of classroom training, which consists of orientation about the plant and the hazards of liquefied natural gas. Then the trainees are given 6 months' on-the-job training that requires them to work with each of the plant operators. During the on-the-job training period, trainees review Alagasco's plant operating, fire, security, and emergency manuals and videotapes and accompanying manuals. Also, trainees are required to participate in emergency drills. Before trainees are allowed to operate the plant without the supervision of an operator, they must pass a proficiency test which they are allowed to retake if their score is unacceptable. All operators are required to retake the test approximately every 6 months. Operators are required to attend the Texas A and M University Liquefied Natural Gas Firefighting School.

The State of Alabama, because of its certification under section 5(a) of the Natural Gas Pipeline Safety Act (49 U.S.C. 1674 (a)), is responsible for the inspection and enforcement of Federal safety standards and practices applicable to this facility, and the Materials Transportation Bureau (MTB) of the U.S. Department of Transportation (DOT) is responsible for monitoring the State, which has adopted the MTB Federal standards established under this chapter.

At the time the Pinson plant was constructed, there were no standards for the construction of natural gas liquefaction plants. However, 49 CFR Part 193 states that the construction, operation, and maintenance of such plants, and the qualification and training of personnel employed at such plants, must comply with current standards and that facilities that are replaced or significantly altered must comply with Federal regulation 49 CFR 193.2005(b), which states, in part, that the design, installation, and construction of a facility "must meet the applicable requirements of the National Fire Prevention Association [NFPA] Standard 59A (1972 edition)." The current NFPA standard requires a distance of 50 feet between equipment containing volatile gases and control rooms, offices, shops, and other occupied structures.

At the Pinson plant the building housing the control room and the boiler room was within 24 feet of equipment that contained volatile gases and liquids. The Safety Board is concerned that if the building is rebuilt at the same location, it could be subject to damage in similar accidents. The building should be reconstructed in compliance with 49 CFR 193.2005(6). The Board is further concerned about the potential for accidents if the operators and trainees do not follow the plant operating manual and if the plant is not maintained as designed.

The National Transportation Safety Board determines that the probable cause of the accident involving the failure of a weld on an aluminum tank and the release and ignition of methane was the failure of the Alabama Gas Company to promptly repair or take other remedial measures for restoring safe operations once it became aware that a plate attached to vessel 17.23A had partially failed.

Therefore, the National Transportation Safety Board recommended that the Alabama Gas Corporation:

> When reconstructing the control room and boiler room building at its Pinson, Alabama, natural gas liquefaction plant, provide a minimum separation of 50 feet between the building, which may contain numerous ignition sources, and equipment containing flammable gases. (Class II, Priority Action) (P-86-3)
>
> Develop and implement a program for monitoring compliance with its operating procedures by employees at its natural gas liquefaction plants, and correct deficient actions. (Class II, Priority Action) (P-86-4)
>
> Develop and implement maintenance practices at its natural gas liquefaction plants in compliance with applicable standards (49 CFR Part 193 and the National Fire Prevention Association Code), and maintain the operating equipment in optimum condition. (Class II, Priority Action) (P-86-5)
>
> Develop, in coordination with local emergency response agencies, a system independent of the telephone to notify without delay fire, police, or other local safety officials about emergency conditions at its natural gas liquefaction plants. (Class II, Priority Action) (P-86-6)
>
> Revise its engineering flowsheet and operating manual for its natural gas liquefaction plants to reflect accurately current facilities and keep the flowsheets and manuals current. (Class II, Priority Action) (P-86-7)
>
> Determine through inspection of each valve and pipe system identified by number on the engineering flowsheet that all valves and pipe systems are identified correctly by an identification tag and that each tag is legible. (Class II, Priority Action) (P-86-8)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

/s/ JIM BURNETT
Chairman

/s/ PATRICIA A. GOLDMAN
Vice Chairman

/s/ JOHN K. LAUBER
Member

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March 22, 1986