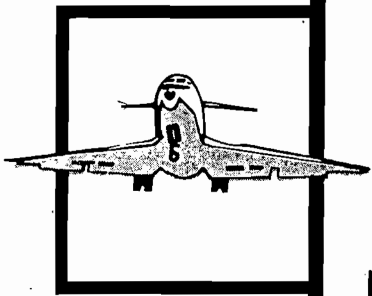
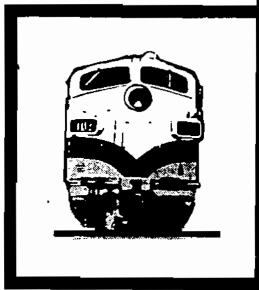
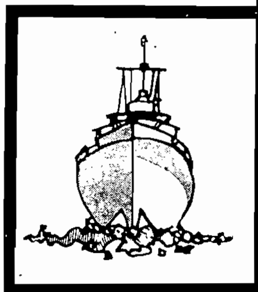


NATIONAL TRANSPORTATION SAFETY BOARD



WASHINGTON, D.C. 20594

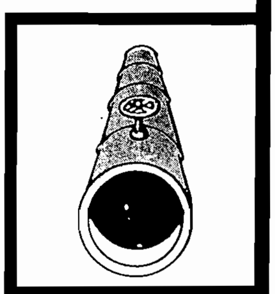
PIPLELINE ACCIDENT REPORT



CONSOLIDATED GAS SUPPLY CORPORATION PROPANE PIPELINE RUPTURE AND FIRE

RUFF CREEK, PENNSYLVANIA

JULY 20, 1977



REPORT NUMBER: NTSB-PAR-78-1

UNITED STATES GOVERNMENT

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16. Abstract At 4:30 a.m., e.d.t., on July 20, 1977, a 12-inch propane pipeline, owned by the Consolidated Gas Supply Corporation, ruptured near the town of Ruff Creek, Pennsylvania. The liquid, under 450-psig pressure, escaped from the pipeline, vaporized, and propane gas fumes settled like a fog over the bottom of a valley. About 6 a.m., two men in a pickup truck entered the propane cloud; the truck stalled and the propane gas ignited when an attempt was made to restart the truck. A flash fire, approximately 100 yards wide, followed a streambed located along the bottom of the valley and burned everything in its path for a distance of 1 mile.

As a result of this accident, the 2 persons in the truck were killed, the truck was destroyed, 57 head of cattle were killed, overhead power and telephone lines were destroyed, a hay storage shed containing 450 bales of hay was burned, 1,800 barrels of propane burned, and a meadow and wooded area 1 mile long by 100 yards wide was burned.

The National Transportation Safety Board determines that the probable cause of the accident was the failure by stress-corrosion cracking of a 12-inch propane pipeline which had been subjected to earth subsidence caused by previous coal mining operations underneath the pipeline.

The fatalities and property damage resulted from the escaping liquid which vaporized and settled in a valley where it was later ignited by an electrical spark from a truck.

17. Key Words Propane fire; liquefied petroleum gas (LPG); stress-corrosion cracking; stopples; coal mining; earth subsidence; LPG statistics; cathodic protection; magnetic-particle-inspection techniques.		18. Distribution Statement This report is available to the public through the National Technical Information Service, Springfield, Virginia 22151	
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CONTENTS

NATIONAL TRANSPORTATION SAFETY BOARD
WASHINGTON, D. C. 20594

PIPELINE ACCIDENT REPORT

Adopted: January 12, 1978

CONSOLIDATED GAS SUPPLY CORPORATION PROPANE PIPELINE RUPTURE AND FIRE RUFF CREEK, PENNSYLVANIA JULY 20, 1977

SYNOPSIS

At 4:30 a.m., e.d.t., on July 20, 1977, a 12-inch propane pipeline, owned by the Consolidated Gas Supply Corporation, ruptured near the town of Ruff Creek, Pennsylvania. The liquid, under 450-psig pressure, escaped from the pipeline, vaporized, and propane gas fumes settled like a fog over the bottom of a valley. About 6 a.m., two men in a pickup truck entered the propane cloud; the truck stalled and the propane gas ignited when an attempt was made to restart the truck. A flash fire, approximately 100 yards wide, followed a streambed located along the bottom of the valley and burned everything in its path for a distance of 1 mile. The flames were over 100 feet high at the point of the rupture and burned for 14 hours until the remaining propane liquid in the pipeline could be isolated in the pipeline by the use of valves and stopples.

As a result of this accident, the 2 persons in the truck were killed, the truck was destroyed, 57 head of cattle were killed, overhead power and telephone lines were destroyed, a hay storage shed containing 450 bales of hay was burned, 1,800 barrels of propane burned, and a meadow and wooded area 1 mile long by 100 yards wide was burned.

The National Transportation Safety Board determines that the probable cause of the accident was the failure by stress-corrosion cracking of a 12-inch propane pipeline which had been subjected to earth subsidence caused by previous coal mining operations underneath the pipeline.

The fatalities and property damage resulted from the escaping liquid which vaporized and settled in a valley where it was later ignited by an electrical spark from a truck.

Contributing to the amount of propane burned and to the time taken to isolate the failed pipeline section was the absence of provisions to detect the failure in a timely manner and to isolate the failed section.

INVESTIGATION

The Accident

At 4:30 a.m., e.d.t., on July 20, 1977, a 12-inch propane pipeline owned by the Consolidated Gas Supply Corporation (Consolidated) ruptured near the town of Ruff Creek, in Greene County, Pennsylvania. The escaping propane vaporized rapidly and filled a small nearby valley.

About 6 a.m., two men in a pickup truck were driving south through the valley on Rural Township Road T-552 and encountered what appeared to be an early morning fog. The truck's engine stalled and the men got out of the truck and attempted to push it up a hill and out of the vapor. At 6:05 a.m., the driver of the truck turned on the ignition, tried to restart the engine, and the resulting spark ignited the propane vapor. Flames more than 100 feet high erupted with a loud roar and flashed back to the rupture in the pipeline, which was located 300 feet to the north of the stalled truck. (See figure 1.)

The flames also followed the vapor cloud south for 4,000 feet along the Craynes Run stream, where it burned everything in a 300-foot-wide path. (See figure 2.) The propane vapor cloud had followed the stream, which ran along the bottom of the valley, because, unlike natural gas, propane is heavier than air and gravitates to the lowest terrain features. The vapor cloud was between 250 and 350 feet wide and was about 30 feet higher than the streambed on the downwind side where the truck had stopped. The 30-foot-high electric wires along the bottom of the valley melted from the fire and interrupted electric service to the area at 6:05 a.m. After the vapor burned, the main fire was concentrated at the pipeline rupture.

Both men and the truck were engulfed in flames after the initial explosion. One of the men walked 1,400 feet, with his clothes still on fire, to a farmhouse to seek help. An ambulance was called and arrived at 6:25 a.m.; both men were taken to the hospital at Waynesburg, Pennsylvania, 9 miles away.

By 6:45 a.m., two Pennsylvania State Police officers had arrived at the scene and volunteer firemen from two fire departments were using foam in an attempt to put out the 70-foot-high flames that were burning over the pipeline rupture. The state troopers radioed their dispatcher and requested that the operators of pipelines in the area be notified of the line break.

The police dispatcher started calling all of the gas companies in the area because he did not know who owned the pipeline. There were two signs marking the location of the propane pipeline at a road crossing within 100 feet of the pipeline break, but nobody noticed or called the telephone number that was clearly marked on the signs.

Figure 1. Pipeline rupture about 5 hours after ignition. Flames are 40 feet high. Burn line of propane vapors extended 4,000 feet to the south.

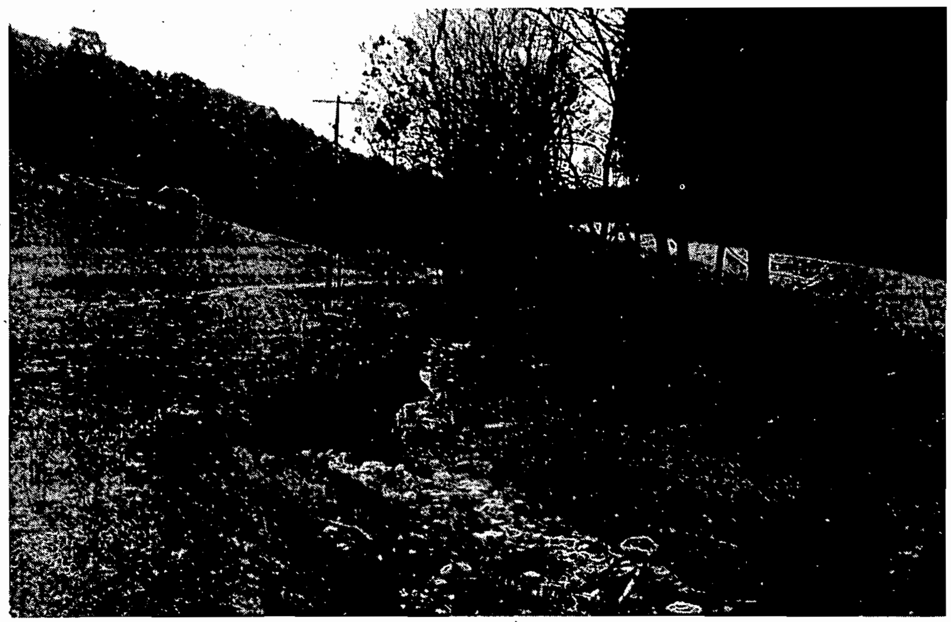

Figure 2. View of 300-foot-wide burn area south along Craynes Run Stream from Township Road T-552.

At 7:05 a.m., a representative of the Columbia Gas Transmission Corporation arrived at the scene and verified that the break was not in his company's natural gas pipeline. Because of his knowledge of hazardous materials, he informed the volunteer firemen that it was a propane fire which would be safer if it were left to burn than if it were put out and allowed to vaporize again. The firemen followed his instructions, pulled back their equipment, and blocked access to the area.

At 7:10 a.m., a Peoples Natural Gas Company (Peoples) foreman at Waynesburg told the police dispatcher that Peoples did not have any gas pipelines in that area. A few minutes later, the Waynesburg Fire Department called the Peoples foreman and informed him that it was a propane pipeline failure. The Peoples foreman then realized that the pipeline probably belonged to Consolidated and notified the company.

At 7:15 a.m., Consolidated dispatched men to the accident scene. However, the Peoples foreman was closer to the site and was asked to help shut mainline valves.

At 7:20 a.m., the Peoples foreman switched on his mobile short wave radio, which broadcasted on the same frequency as that used by their "sister" company, Consolidated, and headed toward Ruff Creek with two helpers. The men from Consolidated described over their mobile radio the location of the Ruff Creek valve setting to the men from Peoples and told them which of several valves to close. At 7:38 a.m., Peoples reported that the mainline gate valve near Ruff Creek was closed and that the fire was 1/2 mile north of there. Consolidated then asked the Peoples crew to close the "Marianna" valve, the next valve downstream, 6 1/2 miles north of the fire because they would get there faster than Consolidated. At 8:30 a.m., Peoples closed the mainline gate valve at "Marianna," 10 minutes before Consolidated arrived. Consolidated, after checking to make sure the right valve was closed, proceeded to the scene of the accident.

At 8:40 a.m., a mainline gate valve was closed at the State line between West Virginia and Pennsylvania by another Consolidated crew because, at the time the crew from West Virginia was dispatched, it was thought that the line break was between the "State Line" gate and the "Ruff Creek" gate.

At 9:05 a.m., 4 1/2 hours after the pipeline failure, the first crew from Consolidated arrived at the accident site. At that time, the 40-foot-high flames from the burning propane vapors were confined to a small area directly over the break in the pipeline. The break was 86 feet east of township road T-550, and 33 feet east of the Craynes Run stream. (See figure 3.)

At 9:20 a.m., a second work crew arrived and determined that this was the same area where some pipeline maintenance work had been done in

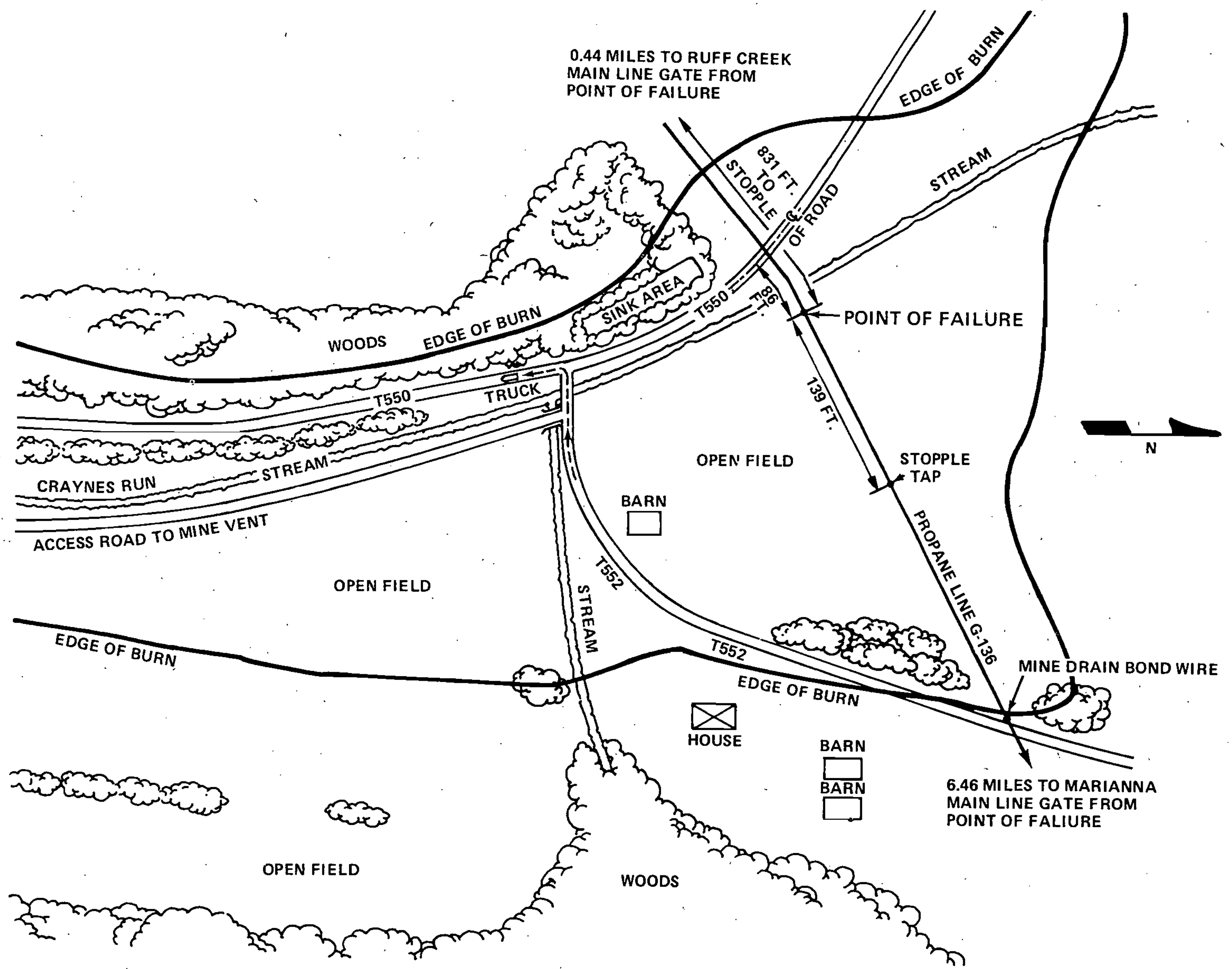

Figure 3. Plan of accident site.

1974. At that time, pipeline stopples 1/ had been installed 139 feet northeast and 831 feet southwest of the point where the pipe ruptured in this accident. It was decided to reuse the stopple fittings; two stopples and all of the 12-inch stopple insertion equipment were ordered from a company warehouse in Clarksburg, West Virginia.

Flames from the line break continued to pulsate between 20 to 40 feet high because the propane was vaporizing unevenly in the section of the pipeline that had been isolated between the two closed valves.

At 11:30 a.m., a Consolidated backhoe arrived and began to excavate the buried stopple fitting southwest of the line break; the excavation was completed at 12:35 p.m.

At 1 p.m., the backhoe started to excavate the stopple fitting to the northeast of the break. The flames were only 6 to 8 feet high by this time. When the earth over the pipeline was removed, the pipe rose about 2 inches. The excavation for this stopple fitting also took 1 hour.

At 2:45 p.m., the stopple equipment arrived and was first installed northeast of the line break because that location was closer to the rupture. The setting of the first stopple was completed at 5:15 p.m. (See figure 4.)

At 5:30 p.m., the second stopple was installed on the Ruff Creek side of the break. This stopple was set by 7:20 p.m. Flames over the break began to subside and went out completely by 8:30 p.m., 14 1/2 hours after the fire began and 16 hours after the rupture.

Injuries to Persons

Injuries	Operating Personnel	Rescue Personnel	Other
Fatal	0	0	2
Nonfatal	0	0	0

Damage to Pipeline

A segment of 12-inch pipe, approximately 33 feet long, that contained a 13° overbend which had been made in the field during construction was removed for examination. The pipe had a 10-inch-long fracture which had opened 1/8 to 1/4 inch (See figure 5.) The fracture was approximately in the center of the convex side of the curved region and was oriented transversely to the longitudinal axis of the pipe. Approximately 1,800 barrels (75,600 gallons) of liquid propane were vaporized and burned by the fire.

1/ Equipment used to insert plugs temporarily in a pipeline which is under pressure in order to isolate a section of the pipe for repairs.

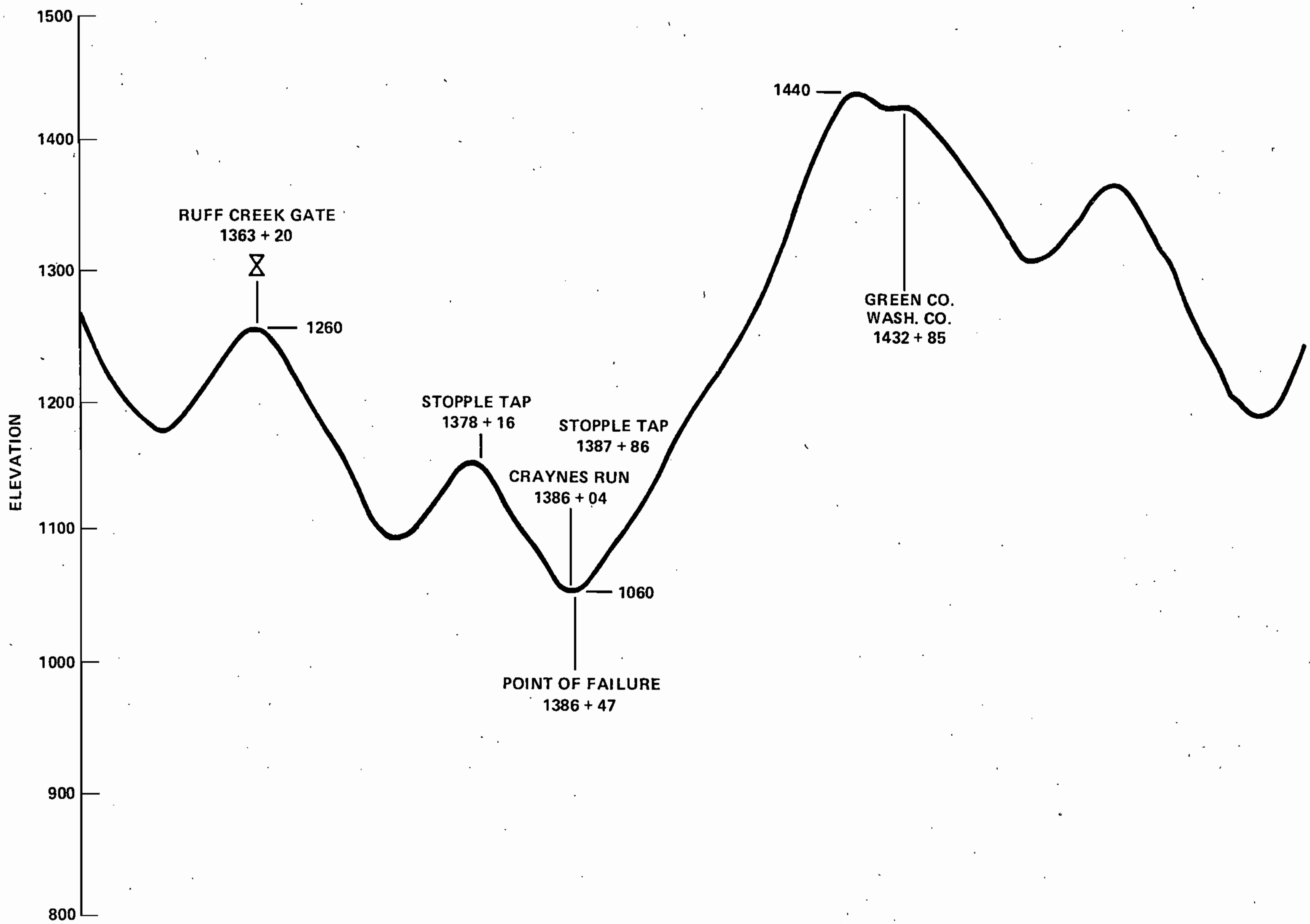

Figure 4. Topographic view of pipeline route.

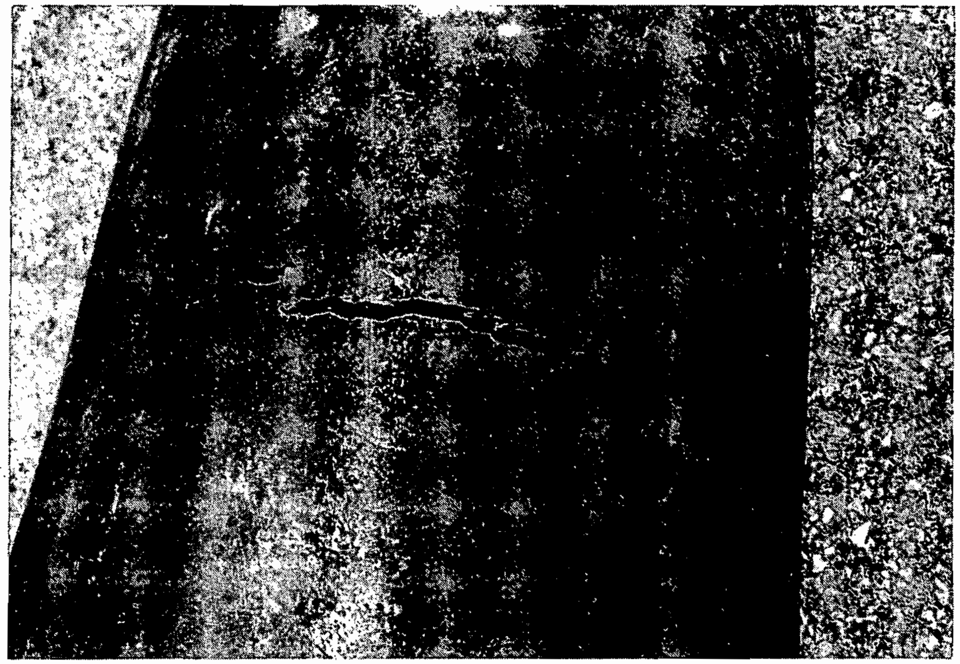

Figure 5. Ten-inch-long crack in 12 3/4-inch outside diameter, bare steel pipe.

Other Damage

Fifty-seven head of cattle nearby, weighing a total of approximately 38,620 pounds, died either of their burns or had to be destroyed because they were blinded by the fire.

The fire destroyed the pickup truck, a hay barn, nearby electric wires and power poles, fence posts and wires, and burned approximately 30 acres of pasture land, 450 bales of hay, and many large trees.

The Pipeline System

The 70-mile-long, 12-inch propane pipeline extended from Consolidated's Hastings Extraction Plant at Hastings, Wetzel County, West Virginia, to its Hutchinson Pump Station near Elizabeth, Allegheny County, Pennsylvania. (See figure 6.) At the pump station the propane is metered and then delivered to the Texas Eastern's pipeline system for transportation to New York State.

The pipeline was originally constructed in 1944 to transport natural gas from West Virginia gas fields to New York. The Pennsylvania portion of the pipeline was constructed by one contractor to the specifications of the New York State Natural Gas Corporation while the West

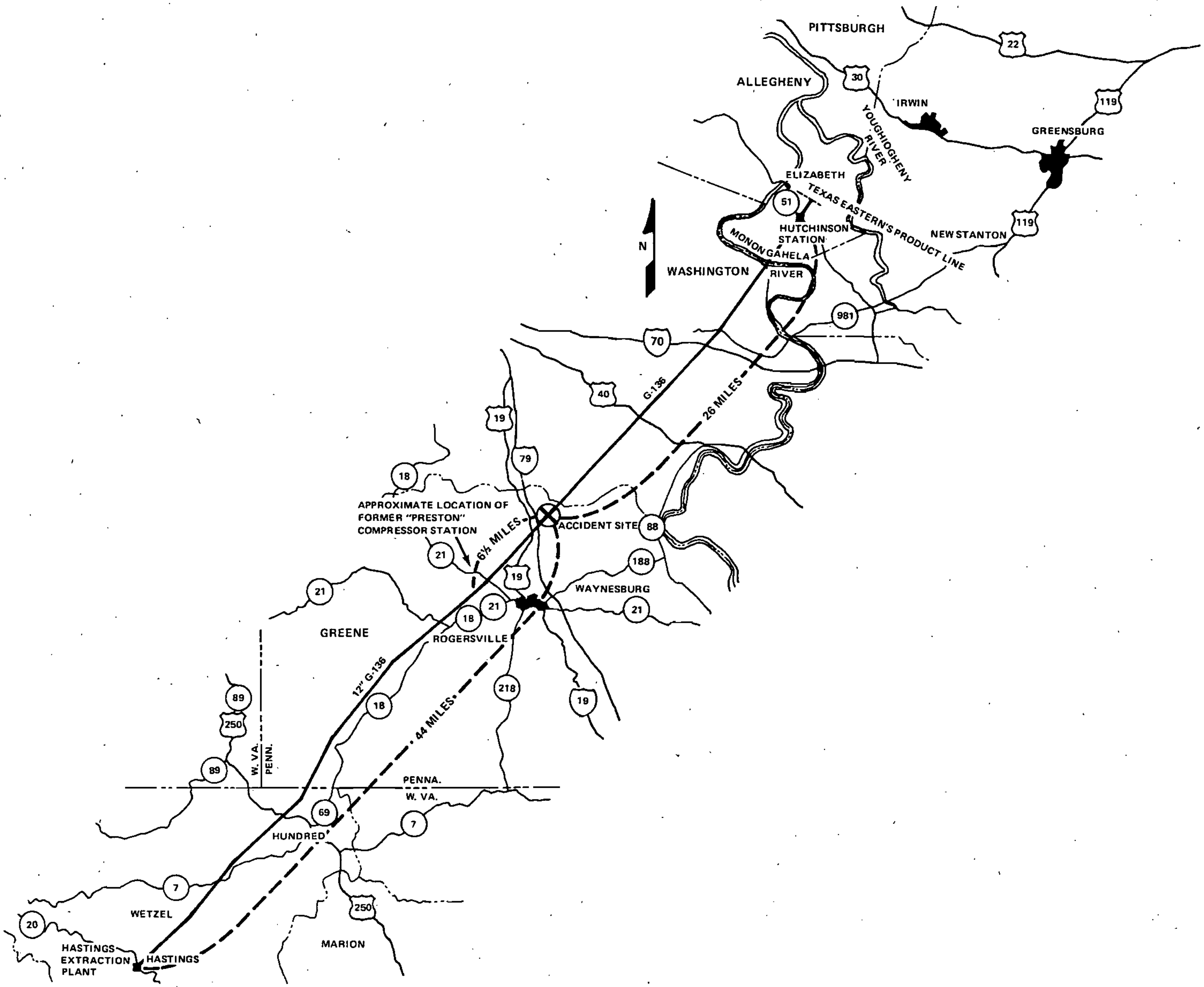

Figure 6. Plan view of pipeline route.

Virginia portion of the pipeline was installed at the same time by another contractor for the Hope Natural Gas Company. Some of the 33-year-old records on this pipeline were not maintained when the two gas companies merged to form Consolidated in 1965. Available records described the pipe, manufactured at the same time for both companies by the National Tube Company, Lorain Works, Lorain, Ohio, as follows:

12 3/4-inch outside diameter,
0.281 (9/32)-inch wall thickness,
37.45 pound per foot,
API-5L seamless steel,
"Grade B line pipe with the following exception:
45,000 psi minimum yield point and 0.30 percent maximum carbon content" 2/;

The report of mill inspection showed:
Pipe was made from open hearth steel,
Carbon content varied from 0.23 to 0.30 percent,
Hydrostatic mill test of 1,800 psi,
Minimum wall thickness 0.245 (as gauged),
Double random lengths with ends beveled 30° for welding,
Elongation in 2 inches was between 30 and 37 percent.

The pipeline was installed without any protective coating. No cathodic protection, such as anodes or rectifiers, was installed on the bare steel pipeline at that time. Joints were welded; a bending shoe was used to field-bend the pipe. The line was completed and placed in service during December 1944. The pipeline was continuously used for natural gas service between 1944 and 1968. Dried natural gas was compressed to a 1,300-psig discharge pressure at the Hastings plant and to a 1,200-psig discharge pressure at the Preston Compressor Station, which was located in Greene County, Pennsylvania, 6 1/2 miles south of the accident site. At 1,200 psig, the pipeline was operating at 60 percent of its 1,983 psig specified minimum yield strength (SMYS), which was calculated using 45,000 psi as the specified minimum yield of the steel used to make the pipe.

In 1968, Consolidated considered converting approximately 70 miles of the pipeline to propane service. Several tests and surveys were made including a pressure test with gas at 1,000 psig; no major leaks were discovered. However, a shut-in leak test at 810 psig indicated leakage at 41.98 cubic feet per year per mile. A leakage consulting firm conducted a 13-day leak survey with a flame-ionization leak detector. Twenty-seven leaks were found, but only one small rust hole leak was determined to be on the body of the pipeline itself and was repaired; the other leaks were on drips, taps, and valve packing on old gas valves which were removed.

2/ From a letter of completion of inspection by Standard Oil Development Company of Linden, New Jersey, for the Hope Natural Gas Company, dated August 17, 1944.

In March 1969, a copper-sulfate electrode corrosion survey was conducted to obtain pipe-to-soil voltage potentials. As a result of the survey, 11 miles of the pipeline were cathodically protected by rectifiers, 42 miles were "hot spot" protected by the installation of 1,394 magnesium anodes, and 17 miles were provided with stray-current bonds.

The pipeline in the area between Interstate Highways 70 and 79, where the accident occurred, was not surveyed because of stray currents from nearby coal mining electrical systems. Four stray-current bonds were made to underground coal mines which used direct-current electrification systems.

An internal inspection survey, where an electronic "pig" is propelled through the pipeline at a low rate of speed, was conducted during May 1969. The wall thickness was recorded on a strip chart log which was correlated to certain known locations along the pipeline. The primary reason for conducting the survey was to determine areas of severe corrosion. The survey indicated points of severe corrosion in a distance of approximately 20,000 feet of pipeline between Interstate 79 and the Monongahela River which included the segment of the pipeline in this accident. However, it was decided that the corrosion was not as severe as indicated because, at other locations with similar survey readings, the pipeline had been dug up and spot checked, and the measurements of actual corrosion pit depths, when correlated to the log readings, were not as severe as indicated. Spot checks were not made and no pipe was replaced between Interstate 79 and the Monongahela River. As a result of the internal surveys, however, approximately 1,250 feet of pipe was replaced in areas of high population.

During August 1969, the entire pipeline was hydrostatically tested. On August 13, 1969, a 25-mile-long segment of pipeline, which included the pipe joint that failed in this accident, was deadweight tested at 1,500 psig for 24 hours. There were no leaks in this segment of the pipeline. There were two corrosion leaks south of Ruff Creek, and approximately 80 feet of pipe was replaced.

Between September 1969, and April 1970, the pipeline was purged and filled with propane and pressurized to 400 psig. The capacity of the pipeline was 762 barrels (32,000 gallons) per mile. On April 15, 1970, the line was officially placed in service and propane was pumped into Texas Eastern's pipeline. The propane pipeline (designated G-136) is normally operated from March through October each year, and each month transports over 1 1/2 million gallons. In 1976, 14 1/2 million gallons of propane were transported through the pipeline. The maximum amount of propane that can be produced at the Hastings plant is 125 gallons per minute, or 178 barrels per hour (7,500 gallons per hour).

In the 2 months before the accident, propane was pumped during 28 days at a daily rate of from 110 to 115 barrels per hour.

The maximum allowable operating pressure (MAOP) of the pipeline is 720 psig which is 72 percent of the 1,000-psig pressure test with gas, 36 percent of SMYS, and 48 percent of the 24-hour hydrostatic field-test pressure.

Pressures for the 2 months preceeding the accident ranged from a low of 330 psig to a high of 450 psig at the suction side of the Hutchinson Station's pumps. At the time of the accident, the pipeline pressure was 504 psig at Hastings and was estimated to be 450 psig (22.7 percent SMYS) at the point of the rupture.

The Hastings Extraction Plant is a $14 million complex that was designed to remove light hydrocarbons from 120 million cubic feet per day of "wet" natural gas. The gas is gathered from several gas fields in West Virginia. The propane extracted from the natural gas by the depropanizer tower also contains a small amount of ethane. On the day of the accident, there was a mixture of 3.85 percent ethane and 96.15 percent propane in the pipeline. This was considered a normal mixture of the two liquids and was the same mixture pumped earlier in the month. It was pumped from Hastings by a 40-hp triplex pump.

The triplex pump was a variable-speed, motor-driven, reciprocating pump. A pressure controller was used to regulate the speed of the pump; the operating pressure was 504 psig. A high discharge pressure shutdown control was located on the pump; the shutdown pressure setting was 575 psig. A relief valve on the pump discharge was set at 600 psig. There was no low discharge pressure shutdown control at the station.

An identical standby pump and appurtenances were located next to the operating pump and were used when the operating pump was shut down for repairs. Each of the duplicate pump installations was sized to pump 100 percent of the propane that could be produced at the plant. This provided a 100 percent standby capacity. The plant was manned continuously, and a pressure chart in the control building indicated the pumping pressure at all times.

There was no meter to measure how much propane was entering the pipeline. All of the pumping equipment was located outside of buildings, but was inside the boundaries of the fenced extraction plant, and within 100 yards of the manned control building. The propane was pumped from Hastings, the originating station, to the Hutchinson station where the pressure was normally increased to inject the propane into a Texas Eastern pipeline.

The pump station at Hutchinson was similar to the installation at Hastings, with the following exceptions:

(1) The pumps were larger (100 hp each) because it was necessary to overcome up to 1,000 psig of pressure in the Texas Eastern pipeline.

(2) The pumps were housed in a building.
(3) There was a turbine, custody-transfer meter.
(4) There was a low-pressure shutdown switch to shut off the pumps automatically at 300 psig and to pump again at 400 psig pressure.

Meteorological Information

The night preceding the accident was humid and very warm. The temperature was between 70° F and 80° F. The wind was calm. It was daylight before 6 a.m., and the fog had lifted in other areas of the county according to witnesses who reported unlimited visibility.

Fire

Propane is a gas at ambient air temperatures, but it is 1 1/2 times heavier than air and flows along the ground contour seeking a lower elevation. When ignited, it produces a much hotter flame than natural gas because there are approximately 2,500 Btu in a cubic foot of propane vapor and only about 1,000 Btu in a cubic foot of natural gas. The flammable limit range of propane is between 2.4 and 9.6 percent by volume in air.

Survival Aspects

One of the men, aged 32, died in a burn center 16 1/2 hours after the accident. Cause of death was flame inhalation and third-degree burns over 90 percent of his body. The other man, aged 26, died in a burn center 16 days after the accident. Death was the result of second- and third-degree burns over 75 percent of his body.

Propane gas is slow burning and has an extremely hot flame. Therefore, the chance of survival is generally low if burns are extensive.

Tests and Research

The 33-foot-long segment of pipe was removed from the pipeline at the point of failure on July 21. An 11-foot-long piece, which included the fracture and the 13° overbend, was selected for metallurgical analysis.

The National Transportation Safety Board retained Battelle Laboratories in Columbus, Ohio, to do the metallurgical analysis. The following observations and photographs in this section are excerpts from the metallurgical report. 3/

3/ A Metallurgical Investigation into the Cause of Failure in a 12-inch-diameter Pipeline Carrying Liquid Propane in Craynes Run, Greene County, Pennsylvania, on July 20, 1977, to the National Transportation Safety Board dated November 7, 1977.

The visual inspection of the pipe showed very little general or pitting-type corrosion on the outside surface. In general, both the outside and inside surfaces of the bare pipe appeared to be in good condition.

To more closely assess the surface condition of the pipe, the surfaces were examined for other cracks by a magnetic-particle-inspection technique. No cracks were found parallel to the longitudinal axis of the pipe on the outside surface. However, cracks were found transverse to the axis of the pipe (parallel to the primary fracture). Cracking occurred within a band about 56 inches long and about 13 inches wide on the convex side of the bend in the pipe. (See figure 7.) The cracks occurred in clusters and were revealed by the magnetic particles. Secondary cracks were found near the primary fracture and up to 13 inches to the north. (See figure 8.) There was a second cluster of secondary cracks about 43 inches south of the primary fracture near the beginning of the overbend curvature. (See figure 9.)

The primary fracture was opened to permit a detailed examination of the fracture surface; a black, oxide-like deposit extended into 30 to 50 percent of the wall thickness. (See figure 10.) The presence of the deposit indicated that the crack was present at this location before the pipeline ruptured.

The clusters of secondary cracks were broken open, and the resulting fracture surfaces were examined. In both cases, the secondary cracks penetrated only up to 20 percent of the wall thickness. The crack surfaces were covered with a black, oxide-like deposit similar to that found on the primary fracture.

The presence of a heavy corrosion product in the cracks indicated that the cracks probably were not actively growing at the time of failure. Some portions of the cracks were intergranular, but because of the corroded sides of the cracks it was not possible to determine if there was a mix of intergranular and transgranular cracking. (See figure 11.) Because there was no evidence of the cracks actively growing at the time of failure and no way to determine the age of the heavy corrosion product in the cracks, it was not clear if the cracks formed while the pipeline was being used to transport natural gas, while the return bond wire was connected to an active coal mine, or after the bond wire was removed in May 1976.

All of the physical measurements of the pipe were normal. The wall thickness was thinner at the fracture but was 0.246 inch, which was within the minimum wall thickness allowed for this size pipe. The bend curvature was normal with about 0.5° of bend per pipe diameter of pipe length, and the maximum outer-fiber strain on the convex side of the bend was about 1 percent.

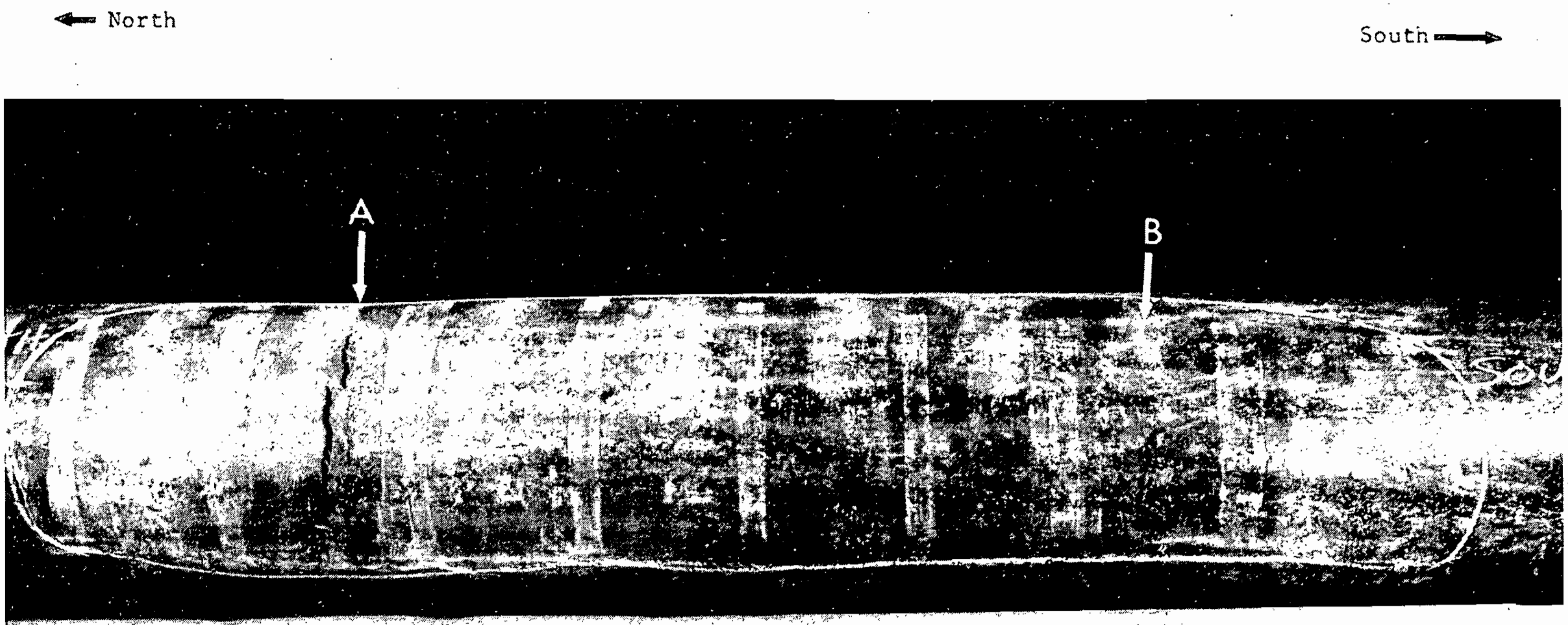

Figure 7. Area of stress-corrosion cracking on top of overbend.

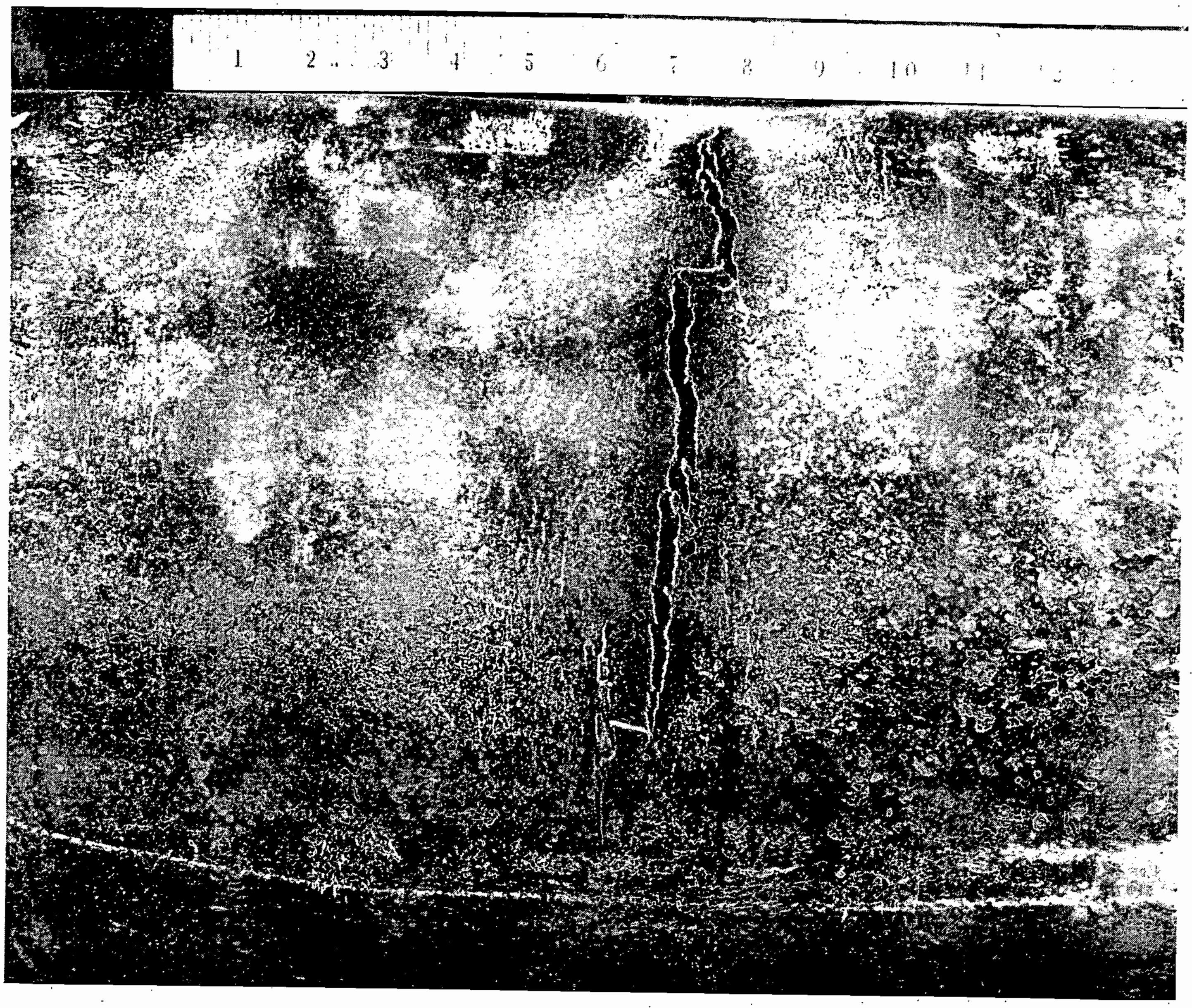

Figure 8. Higher magnification view of the secondary cracks around the primary fracture in area A (see figure 7) on the outside surface of the pipe. About 50 percent of the cracks in area A are shown.

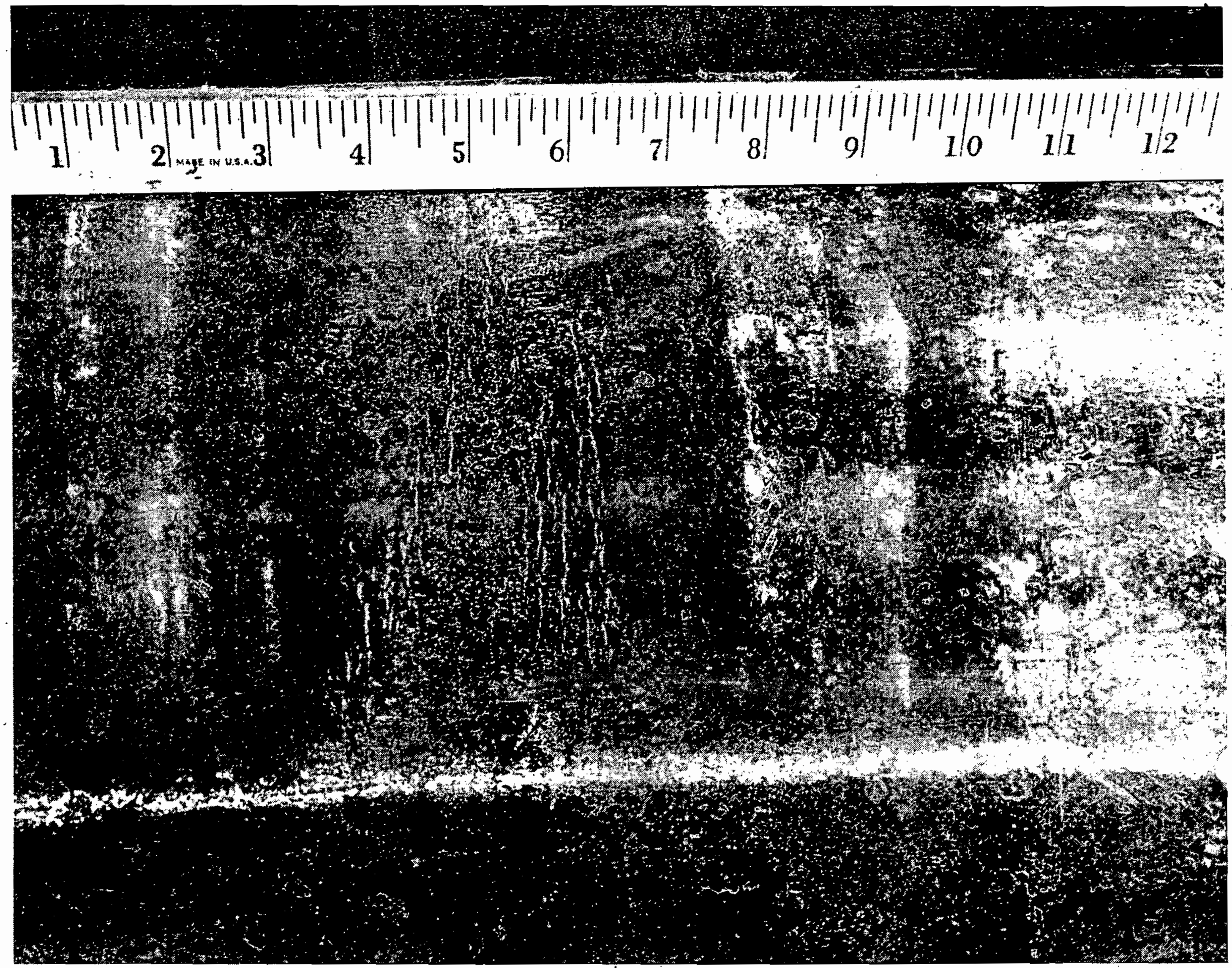

Figure 9. Higher magnification view of the secondary cracks on the outside surface of the pipe in area B (see figure 7). About 50 percent of the cracks in area B are shown.

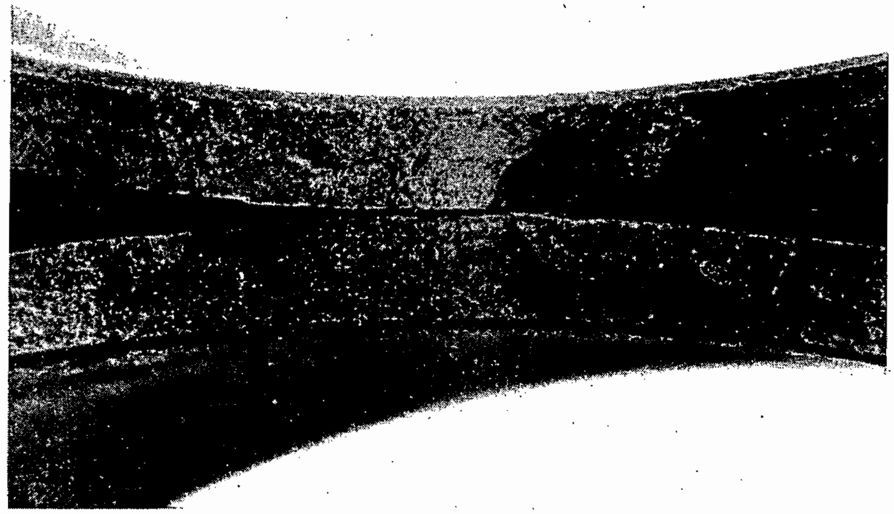

Figure 10. A portion of the primary fracture at higher magnification showing the oxide-like deposit on the fracture surface.

Because the bend curvature did not appear to be excessive, the most likely source of longitudinal tensile stress on the outside of the bend was bending stress produced by axial compressive loads across the bottom of the overbend of the pipe. These loads were believed to originate from the subsidence of the ground in this area. The metallurgist found that the preferential orientation of the cracks transverse to the pipe axis indicated that the most important stresses for cracking were longitudinal to the pipe axis, and that it was reasonable to believe that similar loads accounted for formation of both the original stress-corrosion cracks and the final overload rupture.

The pipe steel in the failed section met the chemical requirements for API-5L Grade B line pipe. The average results of the chemical analysis on two samples were as follows:

Chemical composition, weight percent.

C	Mn	P	S	Si
0.29	1.26	0.039	0.020	0.05

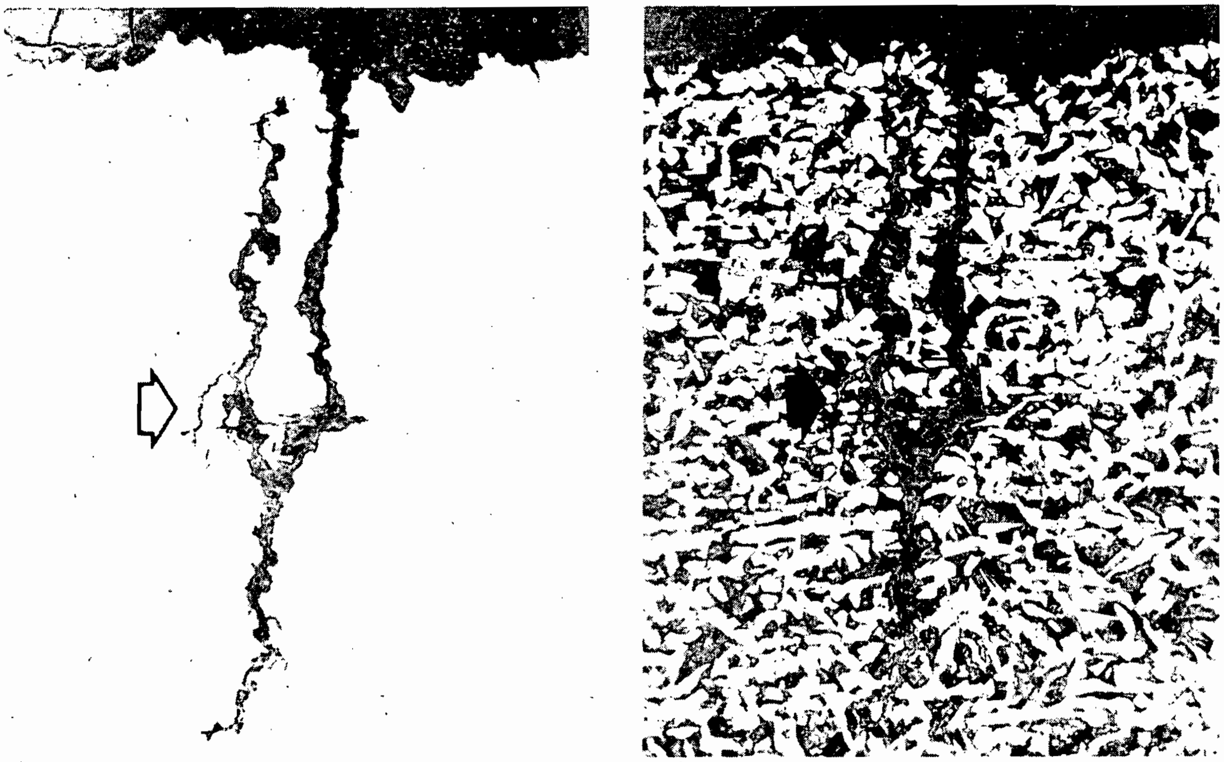

Figure 11. Longitudinal metallographic section through a secondary crack at higher magnification. Left photograph shows crack as polished. Right photograph shows same area etched.

Tensile tests were performed on two specimens of pipe. The yield strength was higher than the 35,000 psi specified minimum yield strength usually specified for Grade B pipe and averaged 51,000 psi. The ultimate tensile strength exceeded the 60,000 psi Grade B minimum and averaged 78,000 psi. The elongation in 2 inches was lower than the standard Grade B minimum of 28.5 percent, and averaged approximately 24 percent.

The metallurgical report concluded that "stress-corrosion cracking appears to be the most probable cause of failure of the pipe."

Other Information

Events preceding the accident. -- At 4:30 a.m., on July 20, 1977, the control board operator at the Hastings plant noticed the pressure on propane line G-136 suddenly drop from 504 psig to 400 psig, the lower limits of the strip chart. The shift leader and two operators investigated to determine the problem. The motor and pump were running, but did not seem to be pumping according to a discharge pressure gauge.

The standby pump normally would have been activated. However, that pump had broken a belt at 4 p.m. on the previous day, and was not scheduled to be repaired until the day crew arrived on July 20.

The Hutchinson Pump Station operator was called at his home and told that there were "pump problems" at Hastings and that they were losing pressure on the propane line. He was asked to go to the Hutchinson station to check for possible problems there or on Texas Eastern's pipeline.

At 5:10 a.m., the Hutchinson operator arrived at his pump station and verified that the Texas Eastern pipeline was operating normally. The suction pressure on Consolidated's propane pipeline, upstream of the operating pumps, was 310 psig. This was 120 psig lower than the normal operating suction pressure. The Hutchinson operator reported these conditions to the Hastings station.

At 5:15 a.m., the crew at Hastings tried to get the pump to operate properly again. They thought it was vapor locked, and tried to get the gas out of it by blowing and cooling it.

At 5:30 a.m., the Hutchinson pump was ordered shut down because the suction pressure there was still dropping. At 5:35 a.m., the Hutchinson pump was shut down; the pressure in line G-136 at Hutchinson continued to fall and then leveled out around 200 psig.

At 6 a.m., 5 minutes before the fire, the Hastings crew leader told the Hutchinson operator that they were still having trouble with the pump and that it would be shut down until the repair crew could find the problem. The pipeline was not shut in and checked for pressure drop.

Coal mining. -- The Bethlehem Steel Company had mined for coal approximately 600 feet below the surface near the accident site. When mining of a coal seam is completed in a certain area, the coal "pillars" that hold up the ceiling of the mine are "pulled" (mined) to maximize the coal production. Without support, the ceiling collapses.

In 1972 and 1973, the area under the pipeline and south of township road T-550 was completely mined (pillars pulled). Later in 1974 and early 1975, the pillars were pulled in the area north of the road, under the portion of the pipeline that ruptured on July 20, 1977.

Whenever a coal seam has been extensively mined and is ready to have its pillars pulled, the coal car rails are removed and the pipeline's cathodic protection bond to the rails is also removed. Pipeline G-136's bond wire to the Bethlehem mine was removed in May 1976.

Often the ground surface is affected by the pulling of pillars, especially if there are no other coal seams or rock formations over the mined-out area to bridge the underground void. In this particular case, there is evidence of extensive ground subsidence. Approximately 200 feet southwest of the pipeline rupture, there was a 6-foot drop in the side of a hill due to underground subsidence. (See figure 12.)

Previous pipeline problems. -- Prior to this accident, there were only two other leaks on this line since its conversion to propane service in 1969. Both were small corrosion leaks; one, in 1974, was 8,200 feet to the north of the point of rupture in this accident. Also in February, 1974, approximately 8 feet of pipeline was forced up about 12 inches above the ground from its buried depth of 30 inches. There was no pipe rupture at that time. However, the pipe raised another 6 inches when the remaining earth cover was removed. Sixteen feet of pipe was cut out of the line starting 11 feet north of the creek. The pipe to the north was again cut 33 feet 6 inches away from the first cut, and this segment, containing the 13° overbend was shifted 16 feet to the south where the overbend then fit the contour of the ditch. A tie-in weld was made at the south end of the overbend, connecting the two existing segments of pipeline back together.

A straight piece of coated pipe, 8 feet 11 inches long, was then installed to fill in the gap to the north of the 33-foot 6-inch-long segment containing the overbend. This new piping configuration was, therefore, 7 feet 1 inch shorter than before, but the pipeline had been lowered by 4 feet to fit the original contour of the ditch as it had before the upheaval.

The pipeline to the south of township road T-550 was also excavated at the same time in February 1974 to relieve the stresses that had been imposed on the pipe because of ground subsidence on the hillside which was evidenced by large cracks in the ground. A "buckle" was found in the pipe 480 feet south of the road, and 42 feet of pipe was replaced. Consolidated inspected the pipe at that time and found no visual indication of corrosion at either location.

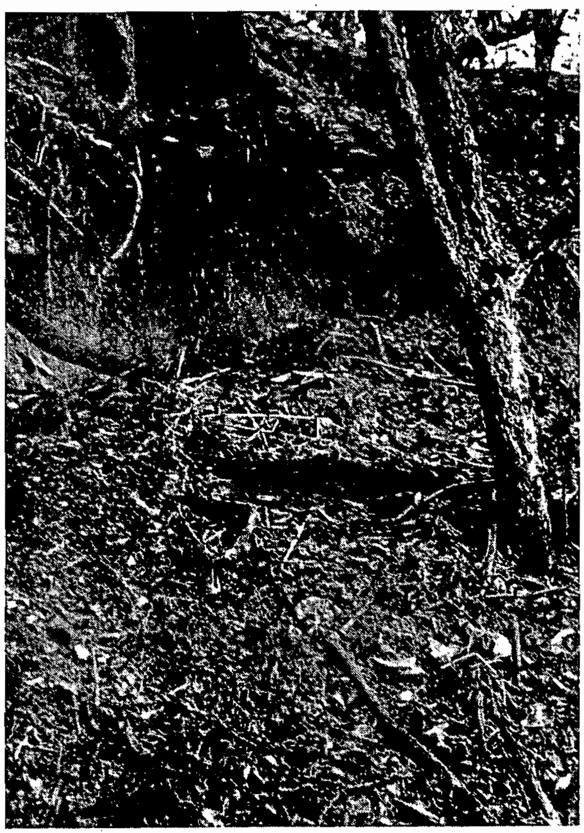

Figure 12. Earth subsidence in burn area west of Township Roads T-550 & T-552.

Natural gas liquids. -- The "wet" natural gas from several gas fields in West Virginia is transported by pipeline to the processing plant at Hastings. The natural gas leaving the plant after processing is dry, of a fairly uniform Btu content, and is odorized for detection if a pipeline leak should develop.

The liquids from the natural gas are separated in the plant and distributed by the most economical means. Propane, one of the natural gas liquids, is classified as a liquefied petroleum gas (LPG) because, at atmospheric pressures and ambient temperatures, it is gaseous; it can be readily contained and stored as a liquid when held under increased pressure or when refrigerated. Propane is a liquid when contained at 192 psig or more pressure and at a temperature of 100° F or less. When a pipeline ruptures and the propane escapes, it vaporizes, expands rapidly to approximately 272 times its liquid volume, and absorbs a tremendous amount of heat for this expansion from any substance with which it comes in contact. The haze or fog commonly associated with spilled propane is not the propane gas itself, but rather the frozen water vapor present in the surrounding air which has been chilled rapidly. Propane is virtually odorless and is not required to be odorized when transported in pipelines as a liquid under 49 CFR 195.

Liquefied petroleum gas pipeline accidents. -- The Safety Board discussed a 5-year average of LPG accidents, compiled from the "Summary of Liquid Pipeline Accidents Reported on DOT (U.S. Department of Transportation) Form 7000-1," in a 1973 report. 4/ From the beginning of the Federal reporting requirements in 1968 through 1972, the Safety Board reported that: "liquefied petroleum products were involved in only 9.4 percent of all reported liquid-petroleum pipeline accidents, but caused 68.9 percent of the reported deaths, 38.1 percent of the personal injuries, and 17.0 percent of the property damage."

A 4-year average from 1973 through 1976 has been compiled using the DOT Form 7000-1 statistics. LPG was involved in 10.1 percent of all reported liquid pipeline accidents, but caused 62.1 percent of the reported deaths, 69.2 percent of the personal injuries, and 42.1 percent of the property damage. Property damage reported for the 4-year period was $3,224,115.

Combining the above 4- and 5-year averages, LPG was involved in only 9.7 percent of all reported liquid pipeline accidents in the past 9 years, but caused 65.5 percent of the reported deaths, 48 percent of the personal injuries, and 30.5 percent of the property damage.

Stress-corrosion cracking -- Stress-corrosion cracking (SCC) is often characterized by the spontaneous failure of a metal resulting from the combined effects of corrosion and stress. It is a complicated

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4/ "Pipeline Accident Report, Phillips Pipe Line Company, Natural Gas Liquids Fire, Austin, Texas, February 22, 1973" (NTSB-PAR-73-4).

phenomenon, and was not commonly recognized in the pipeline industry until 1965 when a 24-inch natural gas pipeline failed from stress-corrosion cracking in Natchitoches, Louisiana, and killed 17 people.

Stress-corrosion cracking is a time-dependent mechanism that depends upon local environmental conditions that are not generally easily changed. One of the many theories which have been advanced to explain the mechanism of SCC is the electrochemical theory. It contends that galvanic cells are established between metal grains, and anodic paths are established by heterogeneous phases. While stressed in tension, the alloy is exposed to a corrosive environment and the ensuing localized electrochemical dissolution of metal, combined with localized plastic deformation, opens up a crack. Protective films that form at the tip of the crack rupture from sustained tensile stress, thereby exposing fresh material to the corrosive environment to begin the cycle again. Figure 13 shows a schematic diagram 5/ of the process:

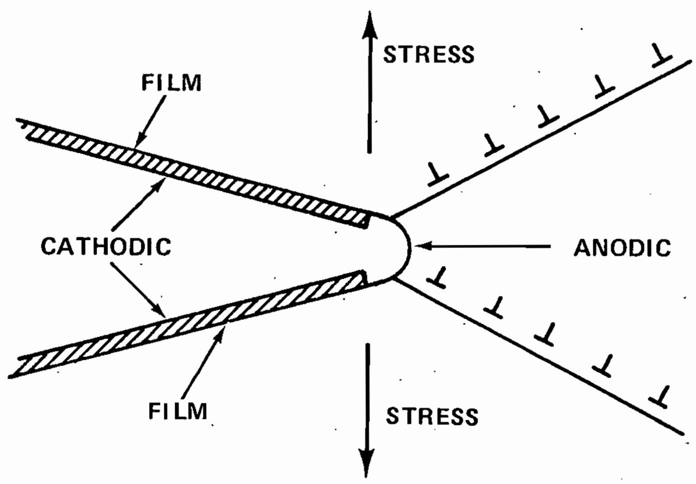

Figure 13. Galvanic cell formation at crack tip allows electro-chemical dissolution of metal at tip.

5/ From a paper presented at George Washington University Short Course No. 376M, Washington, D.C., February 1976, by Oles Lomacky.

In 1965, the American Gas Association (AGA) established a research program to investigate the problem of SCC in natural gas pipelines. The AGA Pipeline Research Committee (NG-18) expanded the program to include research by Battelle Laboratories of Columbus, Ohio. Some of the most complete reports on the research into SCC were presented in several papers at the AGA 5th Symposium on Line Pipe Research on November 20-22, 1974.

No single factor is responsible for stress-corrosion cracking in buried pipelines; a number of factors must exist simultaneously. There are four principal factors required to induce SCC: (1) a susceptible steel, (2) an appropriate chemical environment in contact with the pipe, (3) an appropriate electrical potential at the pipe surface, and (4) a sufficiently high tensile stress.

The most common environment in which SCC can occur is an aqueous solution of sodium carbonate and sodium bicarbonate which can be formed as a product of the galvanic reaction of cathodic protection with a pipe in moist soil. Sodium hydroxide and nitrate solutions, found in ground water, can also promote SCC.

A report of field investigation of SCC, 6/ presented to an AGA symposium in 1974 stated that most of the occurrences of SCC have been near the discharge side of compressor stations. Ninty-two percent have been within 10 miles downstream of a compressor station. Immediately downstream of compressor stations, both the temperature and stresses in the pipe are the highest. It is thought that both of these factors could also be responsible for SCC.

The field investigation report further defined the geographical locations where SCC occurs. There were 21 failures to gas pipelines that were in service at the time of failure (as opposed to more numerous SCC failures (over 200) that occurred during hydrostatic retesting). All but two of the SCC failures occurred in 14 southern States. The two failures that were farthest north also occurred in the mountainous areas of Pennsylvania. One occurred in a county adjoining that of the accident site. The majority of SCC failures occurred on API 5L X 52 steel pipe.

The field investigation report indicated that most of the cases of SCC have been encountered in pipe that was installed before 1956. Most of the failures occurred in pipe installed between 1942 and 1951.

Laboratory research at Battelle has shown that stress-corrosion cracking of pipe steels in carbonate-bicarbonate solutions is possible

6/ Paper presented at AGA 5th Symposium on Line Pipe Research, November 20-22, 1974, by R. L. Wenk, Researcher, Ferrous Metallurgy Section, Battelle's Columbus Laboratories.

only within a relatively narrow range of electrode potentials. 7/ For example, in a sodium carbonate - sodium bicarbonate solution, which probably is typical of those that have caused cracking in line pipe, stress-corrosion cracking can occur only at potentials within about 50 mV of -720 mV, i.e., -670 to -770 mV, versus a copper-copper sulfate reference electrode. The potential at the surface of the pipe where stress-corrosion cracks are growing is not readily measurable by a ground-level, pipe-to-soil-potential survey.

The field investigation report indicated that although a cathodic-protection system was operative on most of the bare steel gas pipelines that failed by SCC, the lines had been operated for many years before the cathodic-protection systems were installed. The report goes on to provide several examples and concludes "there is no way to determine if the cracks started to form before or after the pipe was placed under cathodic protection."

Stress-corrosion cracking cannot occur unless the metal is subject to a tensile stress. The stress must exceed a certain value called the threshold stress. Thus far, it has not been possible to determine the threshold stress for SCC in pipelines. The principal source of stress in most buried pipelines is the internal gas pressure, but residual stresses that were introduced in the cold forming of a bend in the field, and bending stresses produced by axial compressive loads across the overbend of a pipeline caused by earth subsidence, also could exceed the threshold stress limit.

A common method of field-testing for SCC in the gas industry is the magnetic-particle-inspection method. However, there are other suitable nondestructive testing methods. One such method is acoustic emission testing where plastic deformation occurs at crack tips due to stress when the pipe is subjected to internal or external pressures. The resultant pipe deformation emits a sound or stress wave which can be detected and evaluated. 8/

In a DOT-funded report dated February 9, 1976, on the "Transportation of Highly Volatile, Toxic, or Corrosive Liquids by Pipeline," Battelle states on page 19 that: "External stress-corrosion cracking is almost unheard of in liquid pipelines and we are unaware of any instances where it has occurred in a pipeline carrying a highly volatile, toxic, or

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7/ Paper presented at Interpipe 76, Houston, Texas, January 13-15, 1976, "Present Understanding of the Causes of Stress-Corrosion Cracking in Buried Pipelines," by Raymond R. Fessler.

8/ "Acoustic Emission: A New Way to Test Buried Gas Pipelines," by E. A. Lehman, Pipe Line Industry, June 1974.

corrosive liquid." The report further summarizes other papers and states: "The present understanding of the external stress-corrosion problem, as it relates to natural gas pipelines [indicates that] research into external stress corrosion has not progressed to the point where specific preventive practices can be recommended."

Operations and Maintenance.--On April 1, 1970, Subpart F of 49 CFR 195, Transportation of Liquids by Pipelines, became effective. The following sections of Subpart F, Operation and Maintenance, apply to both new and old pipeline systems:

195.402 General Requirements

(a) Each carrier shall establish and maintain current written procedures:

(1) To ensure the safe operation and maintenance of the pipeline system in accordance with this Part during normal operations.

(2) To be followed during abnormal operations and emergencies.

* * * * *

195.408 Communications

Each carrier shall have a communication system that insures the transmission of information required for the safe operation of its pipeline systems.

Consolidated did not have written procedures for operations during either normal or emergency operations.

Consolidated used the Petroleum Safety Data compiled by a committee on safety and fire protection and published by the American Petroleum Institute (PSD 2200-February 1973). (See appendix.)

At the time the pipeline was converted from natural gas to liquid service in 1970, some members of gas operations were trained in 10 areas where liquid operations might differ from gas operations. However, minutes of meetings, lists of who attended these courses, and what training was furnished are not available. However, gas transmission operations and maintenance personnel were assigned to handle the functioning of the liquid pipeline in addition to their normal gas pipeline duties.

Other than discussions in monthly safety meetings on how to handle hypothetical problems or emergencies, no formal training was given to operating personnel.

ANALYSIS

If the propane had contained an odorant like that in natural gas, or an irritant that would have caused coughing or eye irritation, the men might have abandoned their truck and fled on foot. They were less than 100 feet from safety as evidenced by the edge of the burn area 50 feet to the west, and if they had known about the hazards of propane they might not have tried to restart the truck and the vapors might not have ignited.

The pump station operators had never experienced a major pipeline break in the 8 years that the pipeline had been operating in propane service. The fact that a pump had broken down the night before probably influenced the maintenance crew's conclusion that they had another pump problem. If the standby pump could have been operated, they probably would have noticed that the pipeline pressure continued to drop and a pipeline rupture would have been suspected. Without such an indicator, the men should have made more tests using pipeline pressure drops between stations before ruling out the possibility of a pipeline break. There also should have been a meter on the inlet to the pipeline. A meter reading would have indicated that the pump was pumping and that the drop in discharge pressure meant that there was a pipeline break. A low discharge shutdown control also would have indicated the leak.

This pipeline was shut down periodically for various reasons and the lost throughput could easily be made up because the pipeline was oversized; a much smaller line such as a 4- or 6-inch line would have been adequate to pump the relatively small amount of propane produced at Hastings. It also would have been easier to detect a line break on a smaller line. However, the spare 12-inch natural gas pipeline appeared to be in good operating condition when retested in 1969 and the decision to use it for propane service appeared sound.

With the shortage of natural gas today giving rise to excess pipeline capacities, many companies are seeking to convert natural gas pipelines to liquid service. The DOT's Materials Transportation Bureau has proposed a new Subpart G for 49 CFR 195 for conversion of existing steel pipelines to liquid service. All of the steps outlined in the Office of Pipeline Safety Operations Notice No. 77-3 were complied with when this pipeline was converted from gas to liquid service in 1970 although it was not required at that time. However, the new requirements do not mention stress-corrosion cracking and the effect it could have on these converted pipelines.

The 11 1/2 hours required to isolate the leak and extinguish the fire, after the Consolidated crews arrived at the accident site, was typical of a propane accident and not unusually long considering the mountainous terrain, which added to the line drainage and the distant storage location of the stopple equipment. Fortunately, the stopple fittings which had been welded on the pipeline from a previous repair shortened the time required to isolate the failed section. Nevertheless, it still required 8 hours to expose the existing stopple fittings and insert the plugs. This accident was catastrophic, but if the propane vapor had not been ignited by the truck and had migrated several miles farther into a more densely populated area, a tragic catastrophe might have occurred. Although not required by Federal regulations, if this pipeline had closer spaced valves, remotely operated, as well as check valves located to hold-back hill pressure, the failed section would have been isolated more rapidly. As a result of its investigations of pipeline failures involving propane, natural gas liquids, and anhydrous ammonia at Franklin County, Missouri (1970), Austin, Texas (1973), Conway, Kansas (1973), Meridian, Mississippi (1974), Devers, Texas (1975), Romulus, Michigan (1975), and Whitharral, Texas (1976), the Safety Board recommended more stringent regulations for LPG pipelines to prevent accidents.

This pipeline failure may be the first reported case of stress-corrosion cracking in a liquid pipeline that has been verified by laboratory analysis. SCC has generally taken place in natural gas pipelines; the first case was discovered and identified after the Natchitoches, Louisiana, accident of March 4, 1965. That accident took place in a 24-inch X 1/4-inch, 50,000 psi minimum yield strength pipeline operating at 763 psi, and occurred 1 mile downstream of a compressor station where the outlet gas temperature was 100° F.

The pipeline in this accident had operated for 25 years as a natural gas pipeline at an operating pressure of 1,200 psig. The accident site was 6 1/2 miles downstream of the former Preston Compressor Station, a location favorable to SCC based on the documented history of SCC in gas pipelines. However, the higher hoop stress downstream of natural gas compressor stations usually causes SCC where the cracks would be longitudinal to the pipeline. Therefore, although the stress-corrosion cracking cannot primarily be attributed to the failure location in relation to the former gas compressor station, the pulsating pressures from the compressors may have weakened the susceptible steel in this critical location (within 10 miles of the compressor station) where the hoop stress was 60 percent SMYS, approximately 2 2/3 times the hoop stress of 22.7 percent SMYS at the time of failure.

Statistically, most cases of stress-corrosion cracking have been found in steel pipe 20 to 35 years old; this pipeline was 33 years old and had been in natural gas service 24 of those 33 years.

Statistically, pipe with 52,000 psi yield strength has been found to be more receptive to stress-corrosion cracking then pipe of a lower yield strength; this pipe, although ordered from the steel mill as API 5L Grade B with a 45,000 psi yield strength actually had, when delivered, a 51,000 psi yield strength. However, too much significance can be placed on the fact that most SCC failures occur with 52,000 psi yield strength pipe, because that grade pipe was used for most of the older gas transmission pipelines.

Because SCC has occurred in a narrow 100 mV potential range in laboratory tests, it would be extremely difficult to determine what the optimum cathodic protection range should be for this bare pipeline without extensive field testing. A layer of rust or mill scale could change the potential in the pipe considerably. On newly constructed pipelines an excellent case can be made for good coating application combined with good coating inspection. A good pipeline coating will isolate the steel from the soil, and thus remove one of the environmental factors necessary for SCC.

Although field investigations of SCC showed that a cathodic-protection system was operative on most of the bare pipelines that failed by SCC, the lines had operated for many years before the cathodic-protection systems were installed. There was no way to determine if the cracks started to form before or after the pipe was placed under cathodic protection.

In the July 20, 1977, failure it was not possible to determine when the corrosion in the cracks took place. It could have occurred in the 24 years that the pipeline was without cathodic protection, or during the 9 years after the mine drain bond was installed. Because the mine drain bond had been removed only 1 year before the failure, and the cracks appeared to be heavily corroded and not actively growing at the time of failure, it is believed that the cracks had formed before the removal of the mine drain bond wire in May 1976.

The corrosion product in the clusters of secondary cracks 43 inches from the primary crack (fracture) was only 20 percent of the pipe wall thickness compared to 30 to 50 percent of the wall thickness found in the fracture. This would indicate that the stresses at the primary fracture near the center of the overbend were the greatest.

Although the residue stresses from the making of the overbend and stresses caused by the additional pressure of the gas stream turning a bend is greatest near the center of the bend, the 13° overbend was correctly made and the curvature was too small to create stresses of the magnitude necessary for SCC while the pipeline operated in gas service. These stresses may have helped, but it was the tensile bending stresses on the convex side of the overbend, produced by axial compressive loads across the bottom of the overbend caused by earth subsidence, that exceeded the threshold of stress necessary for SCC.

The stresses that were great enough to wrinkle the pipe on top of the hill in 1974 and to cause 40 feet of pipe in the valley to raise up and be shortened by 7 feet probably were great enough to cause stress-corrosion cracking in the overbend. These stresses probably had been on the pipe for between 1 and 2 years or whenever the surface ground subsidence occurred after the coal pillars were pulled in 1972-73. It is possible that if stress-corrosion cracks 20 to 50 percent deep had already formed, they may not have been visible to the naked eye even if the overbend had been examined for possible failures.

The removal of the 7 feet of pipe probably relieved the bending stresses and the stress-corrosion cracks became inactive because one of the necessary elements (stress) of SCC was removed or reduced. The presence of these inactive, corroded cracks, however, would act as stress intensifiers that could result in rupture with the slightest increase in load; it is also possible that such a load increase occurred on July 20, 1977, from earth subsidence in the vicinity of the pipeline.

It is not known when the large 6-foot subsidence in the hillside occurred. It was not there when the pipeline was repaired in 1974. But the pipe was again stressed by coal mining activities sometime during 1974-75 when the pillars directly under the ruptured portions of the pipeline were removed. The pipe only raised 2 inches when pipeline near the rupture was excavated. Although this indicated that the pipe was under some stress, the amount of stress could not be determined and would appear to be less than the 1974 stresses. However, without knowing the elevations of the pipeline before and after failure, it is possible that the floor of the valley itself subsided and stressed the overbend to unknown limits.

Because there is no way to determine that subsidence will not occur in the area again, additional stress could again be placed on the pipeline. Also, because stress-corrosion cracking depends on time and local environmental conditions, it is possible that there are more stress-corrosion cracks in the pipe which have not stopped growing. Therefore, the sagbend located 30 feet south of the failed overbend should be inspected by the magnetic-particle-inspection technique for signs of SCC before the pipeline is again placed in operation in March 1978, for the 1978 season.

The internal hoop stress was only 22.7 percent of SMYS at the time of failure. This was approximately one-third of the stress that the line was subjected to when used for natural gas service. The operating pressure of 500 psig is conservative, and it does not greatly affect stress-corrosion cracking and cannot be lowered enough to help alleviate the SCC problem.

The pipeline was well marked and the telephone number of Consolidated was plainly printed on the readily accessible signs. Obviously, none of the emergency personnel or nearby residents found this information on the sign because Consolidated was not called.

Consolidated did not adhere to 49 CFR 195.402(a)(1) and (2), as required, because they had no written procedures for normal or emergency operations.

The API Petroleum Safety Data was mainly for insuring safe repairs to liquefied petroleum gas pipelines after a rupture had already taken place, and did not contribute to pipeline operations safety.

The ad hoc handling of pipeline emergencies was not adequate. There were no records kept to indicate which operators at the Hastings plant, if any, had been adequately trained when the pipeline was converted to propane. There was also no record of the training that had been furnished within the 10 broad categories taught that would specifically assist operators to determine the differences between pipeline breaks and pump malfunctions.

The night crew on duty during the accident also might not have obtained the benefit of the same instructions or training given in monthly safety meetings to day crews. Much of the training was on-the-job training which could vary considerably because the instructors probably were not trained to teach. Most of the training probably had more to do with plant operations and maintenance than with pipeline operations.

The National Transportation Safety Board has investigated three other accidents in which the communications systems were inadequate. In one of these, at Hearne, Texas, 9/ the Board found that regulation 49 CFR 195.408, Communications, was vague and therefore unenforceable. The regulation is not specific enough to guide the pipeline company to provide adequate information for the safe operation of pipelines. On August 1, 1973, the Board recommended that DOT's Office of Pipeline Safety amend 49 CFR 195.408 (Recommendation No. P-73-30).

In a letter from DOT's Assistant Secretary for Environment, Safety, and Consumer Affairs dated May 1, 1974, it was stated that the Office of Pipeline Safety would consider more definitive regulations on the information that a communications system should transmit. To this date, there have been no admendments to 49 CFR 195.408.

9/ "Pipeline Accident Report, Exxon Pipe Line Company, Crude Oil Explosion at Hearne, Texas, May 14, 1972" (NTSB-PAR-73-2).

This accident again illustrates the need for more explicit regulations on communications. Although the telephone line between pumping stations is a form of communications, correlated data concerning flows, pressures, etc., were not automatically transmitted to a central control point such as the gas dispatching control center at Consolidated's headquarters at Clarksburg. If other persons, such as gas field supervisors, who were also in charge of operations and maintenance of the liquid pipeline, had known about the malfunction, field personnel might have been dispatched to look for a possible leak.

There are also sophisticated computer-type supervisory control equipment available which would automatically signal a rupture of this magnitude. Although not required by 49 CFR 195.408, many companies transporting hazardous LPG's use this type of supervisory control equipment. Automatic shutdown valves are also not required by current regulations, but are used by many companies transporting propane by pipeline.

Pipeline transportation of an unodorized LPG poses hazards that are unique and which cannot be compared with the less volatile and consequently less hazardous heavier hydrocarbon liquids for which 49 CFR 195 was primarily established. The Safety Board continues to consider the transportation of LPG the most serious of pipeline accident problems. For 5 years the Board has recommended more stringent regulations for LPG transportation. The Board again emphasizes the fact that although LPG was involved in less than 10 percent of the reported liquid pipeline accidents in the past 9 years, the LPG accidents caused 66 percent of the fatalities, 48 percent of the personal injuries, and 31 percent of the property damage.

CONCLUSIONS

Findings

1. The leaking propane went undetected for 1 1/2 hours after the failure because no leak detection equipment had been installed and because the pump station personnel at Hastings thought they were having pump vapor lock problems.

2. Because there was no meter at the originating pump station on this propane pipeline, there was no way to detect a leak by comparing the propane volume entering the pipeline with the volume leaving the pipeline.

3. Consolidated did not have written procedures for the safe operation of the pipeline under normal operations or during emergency operations as required by 49 CFR 195.402.

4. Communications, as required by 49 CFR 195.408, is vague and therefore unenforceable. However, Consolidated's communications to safely operate this propane pipeline was not adequate.

5. The leaking propane vaporized and migrated downstream through a valley for 1 mile before it was ignited by an electrical spark from a truck.

6. In the past 9 years liquid petroleum gas (LPG) was involved in less than 10 percent of all reported liquid petroleum pipeline accidents, but it caused 66 percent of all the fatalities, 48 percent of all the injuries, and 31 percent of all the property damage.

7. The rupture in the 12-inch propane pipeline was caused by the propagation of stress-corrosion cracks to the point of failure.

8. Stress-corrosion cracking is affected by time and the crack propagation on this pipeline probably had been developing for a period of years.

9. Earth subsidence due to underground coal mining, which affected the pipeline in 1974, and the removal of coal pillars in the mine directly underneath the pipeline in 1974 and 1975 probably created additional stresses on the pipeline that abetted the stress-corrosion cracking.

10. Although documented for natural gas pipelines, this failure was possibly the first reported case, verified by laboratory analysis, of stress-corrosion cracking on a liquid pipeline.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the accident was the failure by stress-corrosion cracking of a 12-inch propane pipeline which had been subjected to earth subsidence caused by previous coal mining operations underneath the pipeline.

The fatalities and property damage resulted from the escaping liquid which vaporized and settled in a valley where it was later ignited by an electrical spark from a truck.

Contributing to the amount of propane burned and to the time taken to isolate the failed pipeline section was the absence of provisions to detect the failure in a timely manner and to isolate the failed section.

RECOMMENDATIONS

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

-- to Consolidated Gas Supply Corporation:

> "Inspect the field sagbend under the stream and adjacent to the overbend that failed and at any other known locations where the pipeline has undergone settlement of this type with the magnetic-particle-inspection or other suitable technique, for signs of stress-corrosion cracking. Replace the sagbend or other pipe if incipient cracking is present. (Class II, Priority Action)(P-78-1)
>
> "Test pipe for stress-corrosion cracking using a nondestructive testing method such as the magnetic-particle-inspection method or other suitable technique every time the pipeline is exposed for maintenance purposes. (Class II, Priority Action)(P-78-2)
>
> "Establish written procedures to insure the safe operation and maintenance of this pipeline system under normal and emergency conditions as required by Federal regulations. (Class II, Priority Action) (P-78-3)
>
> "Install a meter at the Hastings Extraction Plant on the inlet to the propane pipeline to determine how much liquid is entering the pipeline. (Class II, Priority Action)(P-78-4)
>
> "Investigate the feasibility of detecting pipeline leaks by the use of electronic In/Out flow monitors or other leak detection devices, and install one capable of detecting both small and large leaks. (Class III, Longer Term Action)(P-78-5)
>
> "Establish a control center for the liquid propane pipeline and telemeter all pressure, flow, and other pertinent data necessary for the safe operation of this pipeline to this central location. (Class III, Longer Term Action)(P-78-6)

"Inspect on a random sample basis the segment of pipeline 10 miles downstream of the former Preston Compressor Station, including the area between Interstate Highways 70 and 79 where coal mines are prevalent, for other evidence of stress-corrosion cracking or increased-depth, general corrosion pitting. Increase cathodic protection or consider line replacement in areas where severe corrosion or stress-corrosion cracking is found. (Class II, Priority Action)(P-78-7)

"Train pump station personnel on pump maintenance procedures and how to tell the difference between line pressure losses caused by leaks and by pumps being vapor locked. (Class II, Priority Action) (P-78-8)"

-- to the Materials Transportation Bureau of the U.S. Department of Transportation:

"Expedite the publishing of the Notice of Proposed Rulemaking on regulations for the safe transportation by pipelines of liquefied petroleum gases (LPG). Include a comprehensive section on the communications required for the safe operation of LPG pipelines. (Class II, Priority Action)(P-78-9)

"Include in proposed regulations a section similar to the emergency plan section of the natural gas code (49 CFR 192.615) that will require operators to provide information to persons who live or work within 220 yards of a propane pipeline, and up to 1 mile if located downhill of a LPG pipeline, about the particular hazards of LPG and how to contact emergency response personnel. (Class III, Longer Term Action)(P-78-10)

"Include in proposed 49 CFR 195 regulations, provisions for checking natural gas pipelines that are being converted to liquefied petroleum gas (LPG) service for stress-corrosion cracking. (Class III, Longer Term Action)(P-78-11)"

-- to the American Petroleum Institute:

"Participate in and encourage research into stress-corrosion cracking, especially on older steel gas pipelines that have been converted to liquid service. (Class III, Longer Term Action)(P-78-12)

"Conduct field tests, using acoustic emission testing techniques developed by the gas industry, to determine if highly stressed portions of liquid pipelines can be located, and stress-corrosion cracking can be detected by this means before failure. (Class III, Longer Term Action)(P-78-13)

"Conduct research to develop some form of detector, either as an odorant or irritant, of the presence of liquefied petroleum gas. The detector should be one that will not contaminate the product or make it unsuitable for use with processing catalysts. (Class III, Longer Term Action)(P-78-14)"

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

/s/ FRANCIS H. McADAMS
Member

/s/ PHILIP A. HOGUE
Member

/s/ JAMES B. KING
Member

KAY BAILEY, Acting Chairman, did not participate.

January 12, 1978

APPENDIX

PETROLEUM SAFETY DATA

Compiled By Committee on Safety and Fire Protection

AMERICAN PETROLEUM INSTITUTE
1801 K STREET, N. W. WASHINGTON, D. C. 20006

PSD 2200
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REPAIRS TO CRUDE OIL, LIQUEFIED PETROLEUM GAS, AND PRODUCTS PIPELINES

1. INTRODUCTION

This data sheet is designed to serve as a guide to safe practices in the repairs to crude oil, liquefied petroleum gas (LP-gas), and products pipelines. The data presented herein represent a consensus on a desirable approach to such repair jobs; however, this data sheet should not be regarded as an industry standard. Users of this data sheet are specifically directed to applicable Occupational Safety and Health Administration standards and Department of Transportation regulations.

This data sheet was prepared by the Transportation Safety Committee and was approved for publication by the Committee on Safety and Fire Protection.

2. PURPOSE AND SCOPE

2.1 This data sheet is intended as a guide to safe working practices in the repairs to crude oil, LP-gas, and products pipelines.

2.2 Although it is recognized that an "on-the-job" approach is tailored by the conditions of a particular job, the observance of the suggestions herein should improve the ability to complete a repair without accident or injury.

3. PRELIMINARY KNOWLEDGE

3.1 Qualified supervision is essential. If it is necessary for the designated supervisor to be away from the job, he should assign a responsible and experienced employee to act as temporary supervisor.

3.2 It is essential that all personnel working on pipeline repairs understand the need for careful planning of the job. Employees should be briefed on the procedures to be followed in accomplishing the repair.

3.3 Safety on the job requires a basic knowledge of those elements which in combination may result in a fire. Such knowledge is so essential to personnel performing pipeline repairs that a review is merited.

a. Three elements are necessary for a fire:

1. A combustible material (vapor).
2. A source of ignition.
3. Oxygen (air).

b. A cigarette lighter serves as a practical illustration of the above elements. The combustible material is the lighter-fluid vapor; the source of ignition is a spark from the "flint"; and oxygen is present in the air. If any one of the three is eliminated, there can be no fire.

c. Although a flammable liquid will not burn, its vapor, when mixed in proper proportions with air, will burn and, under certain conditions, may explode. The lowest temperature at which a liquid gives off sufficient vapor to form an ignitible mixture with air is called its "flash point." The flash point of gasoline may be as low as −50 F; gasoline and many other petroleum products will vaporize and form flammable vapor-air mixtures at normal temperatures.

4. PRECAUTIONARY MEASURES AND PROCEDURES

4.1 In ensuring that the pipeline is ready and safe for repair, the supervisor should make certain that proper arrangements have been made to control oil or product flow and cathodic protection rectifier currents.

4.2 Before moving to the job site, the supervisor should check tools and equipment, including personal protective equipment, to make certain they are adequate and in good condition.

4.3 If spilled product at the leak site is known to be toxic, or if the possibility of an oxygen-deficient atmosphere exists, approved respiratory-protective equipment should be available.

4.4 Personnel and equipment should not be permitted in the area of a leak or a break until the contaminated area has been clearly defined. Suitable warnings should be placed where the nature of the product and the likelihood of public access to the area warrants; "DANGER" and "CAUTION" placards are suggested for such purpose. "DANGER" placards should be placed in the immediate vicinity of the leak; "CAUTION" placards should be placed in such outlying areas as appear necessary.

4.5 In instances where repairs are temporary or work is interrupted, the leak site should be barricaded and marked with warning lights or should be fenced to protect against the possibilities of accidents and injuries.

4.6 Spectators should not be permitted within the defined area at any time.

4.7 Surface terrain, direction and velocity of prevailing winds, and proximity to possible sources of ignition such as may be found on highways, on railroads, or in residences should be carefully considered. Roadblocks, if considered necessary, should be erected immediately. A "wind sock" will assist the repair crew in detecting changes in the wind or air currents.

4.8 Since the hazards of fire and explosion exist throughout excavation* and repair work, fire extinguishers should be available and ready for instant use while the work is in progress. When excavation or digging is required in congested municipal or residential areas, it may be advisable for the supervisor to contact the city engineer, the fire chief, the sheriff, or another public official who can help provide spectator barriers, control traffic, and eliminate potential ignition sources where oil or product liberation is involved.

4.9 A combustible-vapor indicator† should be used to determine the concentration of petroleum vapors in the area and to define the hazardous area.

4.10 Matches, lighters (including friction lighters), and smoking materials should be deposited in a place designated as safe. Smoking, if permitted, should only be allowed at a safe location.

4.11 Certain rocks can product incendiary sparks when violently struck with either ferrous or nonferrous metal. In geographic areas where such minerals are present and where volatile flammable liquid is encountered during excavation, the risk of injury to personnel from flash fires can be decreased by keeping the area well drained of liquid.

4.12 When excavations are located in densely wooded areas, in ravines, near creeks, or in low places where movement of air is restricted, special effort is required to vapor-free the area in and around the excavation. Oil-soaked dirt may have to be removed from this type of site to an area a farther distance from the excavation than otherwise would be required.

4.13 Before beginning excavation, it may be necessary to remove spilled oil or product or other combustible material from the work site. Unless powered pumping equipment required for such removal is approved for operation in a hazardous atmosphere, the equipment should be located in an area free of flammable vapors.

4.14 Vehicles and power equipment should not be moved into the area of the leak until the foregoing precautions have been taken. The moving of power equipment into the leak area to expedite repairs should be well planned. The equipment should be removed from the area as soon as its function has been served. Personnel not required to operate such equipment should not be allowed in the immediate area.

4.15 Walls of the excavation should be sloped or shored to prevent cave-ins.

4.16 For ingress and egress, steps should be cut into one wall or a ramp should be provided at one side or at one end of the excavation; large excavations may require additional means of ingress and egress.

4.17 Since tools and equipment should be located upwind of the excavation, spoil should be placed elsewhere. Access to the excavation should also be on the upwind side.

4.18 Spoil should be located well away from the edge of the excavation in order to provide adequate space for employees to safely work and walk around within the repair area.

4.19 The excavation should be large enough in length, in width, and in depth to provide adequate room for personnel required to perform repair or inspection work; additional space may be needed if welding is necessary. The excavation should also provide space for a sufficient amount of bare pipe on each side of the cut or flange separation to attach a bonding cable (see Par. 4.23). The bottom of the excavation should be fairly smooth in order to provide a base for solid footing.

4.20 When excavation is done by mechanical methods, the digging equipment should be operated upwind, if possible. Also, all emergency personnel rescue or fire-extinguishing efforts should be made from the upwind side.

4.21 Whenever possible, temporary repairs should be made without welding or torch cutting. Permanent repairs requiring welding or cutting should be delayed until oil or product cleanup and vapor dissipation have been completed.

4.22 Line cuts, when required, should be made with pipe saws or with mechanical cutters.

4.23 Because of the possibility of electrical currents on the pipeline, an electrical bond should be made across all proposed points of separation before the line is cut or a flange joint is separated. If replacement pipe is required, the pipe joint or joints should also be bonded. The bond should not be removed until repairs have been completed.

4.24 If welding is to be performed, all oils, products, and saturated earth should be removed both from within and around the excavation; also, the excavation and its surrounding area should be checked for vapor. It may be necessary to spread dry dirt around and on the bottom of the excavation.

4.25 When welding or other hot work is required, the following additional precautions should be observed.

a. The excavation should be tested with an indicator to determine that the atmosphere is safe for such work.

b. Where vapor seals or plugs are utilized to prevent the escape of vapor from a pipeline, some positive method of venting or monitoring should be used to ensure against a pressure buildup in the line while hot work is in progress.

c. If oil or product seeps into the excavation after hot work is started, the work should be halted immediately and

*Excavation refers to bellholing, ditching, or any digging required.

†The manufacturers of such instruments have used various descriptive trade names that have led to the acceptance in the industry of the following terms: "explosimeter," "vapor indicator," "combustible-gas indicator," "gas indicator," and "gasoline-vapor indicator." Such instruments will be referred to herein as "indicators."

the oil or product should be removed. The atmosphere should again be tested before hot work is resumed.

4.26 Upon completion of repair, necessary tests and operating checks should be made before placing the line in service.

4.27 Following completion of permanent repair, the site should be restored to its original condition.

5. LP-GAS PIPELINES

5.1 General Conditions

5.1.1 Although the preceding methods and procedures are generally applicable to the repair of pipelines handling LP-gases, personnel assigned to pipeline repair crews should be well informed of the characteristics of the special materials they may handle and the special problems that may be encountered if leaks occur. The most significant characteristics and their related problems are discussed below:

a. The boiling points of LP-gas materials are well below usual ambient temperatures; therefore, any liquid released as a result of a leak usually converts rapidly to vapor. Further, a relatively small release of such a liquid can create a flammable atmosphere over a large area. For example, 1 gal of butane vaporized and mixed with air in proportions corresponding to the lower flammable limit will create a flammable atmosphere to an approximate depth of 3 ft over an area 25 ft in diameter.

b. Since the vapors of LP-gas materials (like those of gasoline) are heavier than air and thus tend to remain close to the ground, the precautions outlined in Par. 4.7 are especially applicable to the potential hazards associated with LP-gas leaks.

c. Since vaporization of leaking LP-gas may freeze the surrounding ground, the danger exists that frostbite may occur in the event the escaping gas should contact exposed parts of the body.

d. The above mentioned refrigerating effect on the ground can also cause difficulties in excavation.

5.1.2 Since LP-gases have substantially greater volatility than crude oil or gasoline (as indicated by the following table of physical properties for propane and butane, typical of the majority of LP-gases), additional precautions may be required when leaks occur.

Approximate Properties of LP-Gases*

	Commercial Propane	Commercial Butane
Vapor pressure, pounds per square inch absolute at 100 F	192	59
Boiling point, in degrees farenheit at 14.696 psia	−51	15
Cubic feet of vapor per gallon of liquid	36	31
Specific gravity of gas (air = 1)	1.554	2.0854
Flammable limits:		
Lower, percent by volume in air	2.4	1.9
Upper, percent by volume in air	9.6	8.6

*Adapted from Standard for the Storage and Handling of Liquefied Petroleum Gases, National Fire Protection Association No. 58, Table A-1, p. 118 (1972).

5.2 Precautionary Procedures

5.2.1 The following precautions (not necessarily in the order shown) should be taken as soon as possible following the detection of a leak:

a. Eliminate all nearby ignition sources (especially those downwind of the leak) and evacuate adjacent areas in possible danger.

b. Determine with an indicator the extent of a flammable atmosphere in the area.

c. If conditions warrant, contact appropriate public officials for assistance in isolating the area, controlling traffic, evacuating nearby residential areas, and controlling spectators.

d. Contact individuals controlling line flow. Advise them to stop pumping and to close block valves if it is necessary to isolate the section of the line that is leaking.

e. If flammable vapors are not accumulating to an extent that causes a serious hazard, consideration should be given to continuing pumping until the LP-gas has been replaced at the point of leakage by a less volatile product. If this procedure can be accomplished, the hazards associated with the subsequent repairs to the line may be significantly reduced.

5.3 Repair Procedures

5.3.1 When leakage has been reduced to a point where it is safe for workmen to enter the leak area and excavate the line, temporary repairs can often be made by installing one of the various types of clamps available for that purpose.

5.3.2 When the clamping procedure is unfeasible or insufficient to permit returning the line to service, safe repair may be effected by hot-tapping the line to provide a means of inserting plugs (stopples) to isolate the defective line section. A bypass may be installed around the leak to permit continued operations while the defective section is drained and repaired. Though the plugs (stopples) are designed to withstand high differential pressure, their effectiveness is influenced by line size, pipe wall condition, and temperature. Consideration should therefore be given to these factors to ensure that the proper type plug is used and that its holding capacity can adequately resist the pressure to be encountered. Tapping and plugging equipment should be installed and operated by skilled personnel trained for the operation, or qualified representatives of the manufacturer should be available to assist.

5.3.3 If it is feasible to remove the pipeline from service for an extensive duration, repairs may be accomplished by hot-tapping the line and installing a connection through which the pipeline's contents can be drained or vented to a place safe for disposal. After draining has been completed and pressure has been reduced to atmospheric, the line may be cut and the defective section replaced. In some instances, flaring may be a desirable means of disposing of the material drained from the line; however, to avoid ignition of any vapors that may have accumulated as a result of the leak, care should be taken in selecting the location for the flaring.

5.3.4 The special tools and equipment needed for safe repair of LP-gas pipelines should be kept in constant readiness at locations known to crews likely to make the repairs. Also, a supply of pipe suitable for making replacements should be kept available for quick transport to any section of the line.

3M—Feb. 1973