National Transportation Safety Board
Washington, D.C. 20594

Pipeline Accident Brief

Accident No.:	DCA09FP007
Accident Type:	Rupture of Florida Gas Transmission Pipeline and Release of Natural Gas
Location:	Near Palm City, Florida
Date:	May 4, 2009
Time:	5:10 a.m. eastern daylight time
Owner/Operator:	Florida Gas Transmission Company
Fatalities:	0
Injuries:	3
Damage/Clean-up Cost:	$606,360
Material Released:	Natural gas
Quantity Released:	36 million standard cubic feet (estimated)
Pipeline Failure Pressure:	854 psig

The Accident

On Monday, May 4, 2009, about 5:10 a.m. eastern daylight time,[1] Florida Gas Transmission Company's (FGT)[2] line 100, an 18-inch-diameter natural gas transmission pipeline, ruptured about 6 miles south of Palm City, Florida. The rupture occurred in a sparsely populated rural area of Martin County and displaced about 106 feet of buried pipe onto the right-of-way between Interstate 95 (I-95) and the Florida Turnpike (SR-91). An estimated 36 million cubic feet of natural gas was released during the accident without ignition. Two parallel FGT natural gas transmission pipelines in the same right-of-way were undamaged.[3] Three minor injuries were attributed to the rupture: two people were injured escaping from a vehicle that lost control and ran off the turnpike, and one member of the Palm Beach County Sheriff's department walked through a dense cloud and inhaled natural gas. The rupture occurred between two automatic shutoff valves (ASV),[4] but only one valve shut in response to the pressure drop on the pipeline.

[1] All times in this report are eastern daylight time unless otherwise noted.

[2] From 2004 through 2006, FGT was owned by Citrus Corp. Cross Country Energy and El Paso Corporation indirectly owned 50 percent of Citrus Corp. In 2006, Southern Union Company purchased 50 percent interest in FGT from Cross Country Energy.

[3] FGT operates a 24-inch (line 200) and a 30-inch pipeline (line 300) in the same right-of-way as line 100.

[4] An *automatic shutoff valve* uses electric- or gas-powered actuators to operate the valve automatically based on pipeline sensor readings. The sensor sends a signal to close the valve based on a preset rate of pressure decay in the pipeline. An ASV does not require human interpretation of the pipeline operations, and it closes automatically based on the established criteria.

Emergency responders rerouted traffic on both SR-91 and I-95 and evacuated a high school and a residential subdivision that were nearby. The FGT control center did not receive any Supervisory Control and Data Acquisition (SCADA)[5] alarms or recognize the rupture from SCADA data. However, emergency response personnel began notifying the FGT control center at 5:49 a.m., after which the control center dispatched three field operators to the scene. By 7:30 a.m., the field operators had stopped the flow of natural gas. Local authorities reopened I-95 by 8:00 a.m. and SR-91 by 11:15 a.m. About 2 hours 20 minutes had elapsed from the time of the rupture to the complete isolation of the flow of gas.

FGT operates more than 4,800 miles of Gulf Coast transmission lines from a control center in Houston, Texas. Lines start near Galveston Bay, Texas, and extend through Louisiana, Mississippi, and Alabama before turning south along the Florida peninsula. At the time of the accident, the FGT system consisted of 25 compressor stations with a mainline capacity of 2.25 billion cubic feet per day. The line 100 rupture occurred between compressor station 20 (upstream) and station 21 (downstream). (See figure 1.)

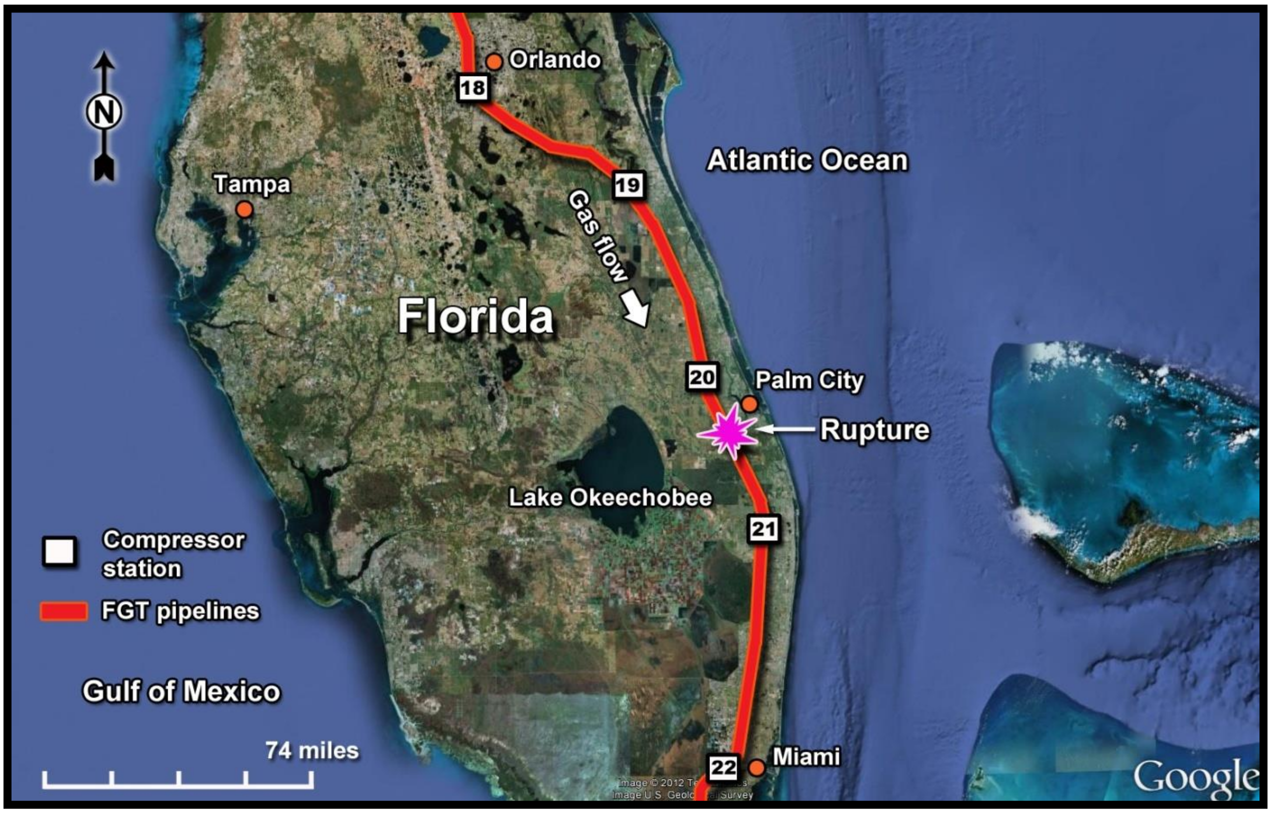

Figure 1. Route of Florida Gas Transmission's three natural gas pipelines along Florida peninsula.

[5] FGT used a computer-based SCADA system to remotely monitor and control the movement of gas through its pipelines. SCADA controllers at the SCADA center in Houston, Texas, monitored operating parameters such as flow rate, pressure, equipment status, and abnormal condition alarms.

Accident Narrative

A section of the ruptured 18-inch pipeline, about 106 feet long and weighing more than 5,000 pounds, was ejected out of the ground and landed near the crater in two pieces,[6] leaving two open ends of the pipe exposed and discharging natural gas. Within minutes, one of two 18-inch ASVs closed, shutting off the gas flow to the upstream (north) end of the rupture and limiting the discharging gas to the south end. (See figure 2.) FGT operated two parallel, interconnected 24-inch and 30-inch natural gas transmission pipelines in the same right-of-way, but the rupture of the 18-inch line did not damage the other two lines. After the rupture, the increased flow of gas through the open pipe began to vent the stored gas volume in the interconnected pipelines and reduce the pressure.

Figure 2. Aerial photograph of ruptured 18-inch pipeline showing venting gas and dislodged pipe near crater.

At the time of the accident, the 18-inch natural gas transmission line was operating at a pressure of 854 pounds per square inch, gauge (psig), or 98.6 percent of the maximum allowable operating pressure (MAOP).[7] The rupture occurred in the final hour of the Sunday evening shift at the FGT Houston control center, before the Monday morning shift change. The releasing gas from the rupture resulted in pressure drops on all three of the interconnected pipelines; however, no SCADA alarms were generated. The pipeline controller did not recognize the line pressure and gas volume reductions as being unusual for that time of day.

[6] The larger of the two pieces was about 104 feet long; the smaller piece was about 1.6 feet long.

[7] Title 49 *Code of Federal Regulations* (CFR) 192.3 defines *maximum allowable operating pressure* as the maximum pressure at which a pipeline or segment of a pipeline may be operated. MAOP is established under 49 CFR 192.619.

Emergency Response

The initial call to the Florida Highway Patrol reporting the accident was made at 5:16 a.m., about 6 minutes after the rupture. The first responders to the accident included the Florida Highway Patrol and the Martin County Hazardous Materials Team, Fire Rescue Department, Police, and Sheriff's Office. By 5:21 a.m., the Martin County Sheriff's Office had received more than 31 calls reporting the incident. .

At 5:33 a.m., Martin County Fire Rescue workers were on scene near the rupture, and by 5:49 a.m. Martin County Fire Rescue made the first notification to the FGT control center, erroneously reporting that a vehicle had struck an FGT pipeline. Within minutes of being notified, an on-call field operator assigned to the Fort Pierce compressor station (station 20) and another assigned to the West Palm Beach compressor station (station 21) were dispatched to the scene by the control center. Believing that the accident involved only an aboveground pipeline marker rather than the buried pipeline, the control center staff remained unaware that a pipeline had actually ruptured.

By 5:59 a.m., the on-scene emergency responders had confirmed that a natural gas pipeline had ruptured. Emergency response personnel established a 1-mile perimeter around the site because of the risk of ignition from a vehicle idling near the rupture. About this time, the Martin County Hazardous Materials Team notified the FGT control center that the accident involved a ruptured pipeline near the I-95 Stuart/Jupiter exit.

After receiving the second call, the FGT gas controllers reviewed SCADA data and identified drops in the pipeline pressures from station 20, drops in pressure at the Martin North Florida Power and Light gas meter, and a noticeable drop in the stored gas volume in the pipeline. At 6:05 a.m., another field operator was dispatched to the accident site. By 6:39 a.m., about 34 minutes after being dispatched, the first FGT field operator reported to the incident command near mile marker 129 and was able to see a white cloud and smell the gas. This field operator became the FGT incident commander.

The control center did not know which of the three lines had ruptured until a field operator on scene saw that the upstream 18-inch ASV was closed. At 7:09 a.m., an FGT field operator closed the remaining downstream ASV, and by 7:30 a.m. no discernible gas was flowing from the ruptured pipe. Emergency responders gradually cleared the roads of debris and restored traffic to I-95 by 8:00 a.m. and to SR-91 by 11:15 a.m.

Injuries and Evacuations

About 6:40 a.m., the fire chief ordered the evacuation of South Fork High School and the Foxwood residential community, both less than a mile southwest of the rupture. The school remained closed for the day, and the fire chief staged additional units in Foxwood to respond to any fires that might break out if gas were to ignite. Emergency responders also closed I-95 and SR-91 in both directions to maintain about a 1-mile perimeter around the ruptured pipeline.

Three injuries were directly attributed to the rupture and gas release. Two people sustained minor injuries while leaving their vehicle after the driver lost control and ran off the turnpike into the right-of-way. The third injury occurred when a member of the Palm Beach

County Sheriff's department walked through the dense natural gas cloud and inhaled natural gas while assisting with the response.

Pipeline Information

History

The ruptured pipeline section[8] consisted of four pipe segments buried to a depth of about 3 feet 9 inches.[9] Two of the 18-inch-diameter ruptured pipe segments were part of the original 1959 installation with a spiral-wrapped, field-applied Polyken 900 general utility polyethylene tape as the primary means of corrosion protection. These two polyethylene-tape–coated pipe segments were manufactured to the American Petroleum Institute (API) Standard 5LX[10] grade X52[11] with a 0.25-inch nominal wall thickness and a direct current electric resistance welded (ERW) longitudinal weld seam. Samples from the pipe material were tested, and the results showed that the mechanical and chemical properties of these pipe segments met the requirements of the API standard.

After the original installation of the pipe, a hydrostatic pressure test was performed to a pressure of 1,085 psig, and an MAOP of 975 psig was assigned to the pipeline. In the latter half of 1971, line 100 was hydrostatically pressure tested again, to 1,320 psig, to qualify portions of the pipeline for Class 3 operation. This resulted in an MAOP of 866 psig, which was in place at the time of the accident.[12]

The NTSB Materials Laboratory examination revealed that the two remaining segments of the ruptured section, downstream of girth weld 3, had been replaced with pipe that was newer than the original pipe segments. (See figure 3.) Each of the newer segments had an ERW longitudinal weld seam and was coated with fusion bonded epoxy. The newer segment farthest downstream had a thicker wall than the other three pipe segments of the ruptured section. The FGT integrity management group stated that the two newer segments[13] were installed in late 2004 because of corrosion features identified during a magnetic flux leakage (MFL) in-line inspection that same year. FGT could not provide records of the replacement project that identified why the work was performed or whether an analysis of the defects was conducted on

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[8] Herein, *section* applies to multiple segments of pipeline; *segment* refers to a single joint of pipe between an upstream and a downstream girth (circumferential) weld.

[9] Pipeline burial depth is measured from the ground surface to the top of the pipe.

[10] The API develops industry-based consensus standards that support oil and gas production and distribution. API 5LX is a specification for line pipe.

[11] Grade X52 signifies that the pipe has a specified minimum yield strength (SMYS) of 52,000 psi. Yield strength is a measure of the pipe's material strength and indicates the stress level at which the material will exhibit permanent deformation. Although yield strength is expressed in psi, this value is not equivalent to a pipe's internal pressure.

[12] Title 49 CFR 192.611 defines the requirements for a change in class location. Class 3 MAOP was 60 percent of the pressure at the SMYS. The SMYS pressure was 1,444 psig for the ruptured pipe.

[13] According to FGT, three 18-inch-diameter segments were installed on line 100 in December 2004: 18.3 feet of 0.25-inch wall thickness API 5L grade X60 ERW, 41.7 feet of 0.375-inch wall thickness API 5L grade X52 seamless, and 39.6 feet of 0.375-inch wall thickness API 5L grade X65 ERW.

the replaced pipe segments. No other maintenance or excavation activities were identified near the ruptured segment. In addition to the tape coating, line 100 had a cathodic protection system.[14]

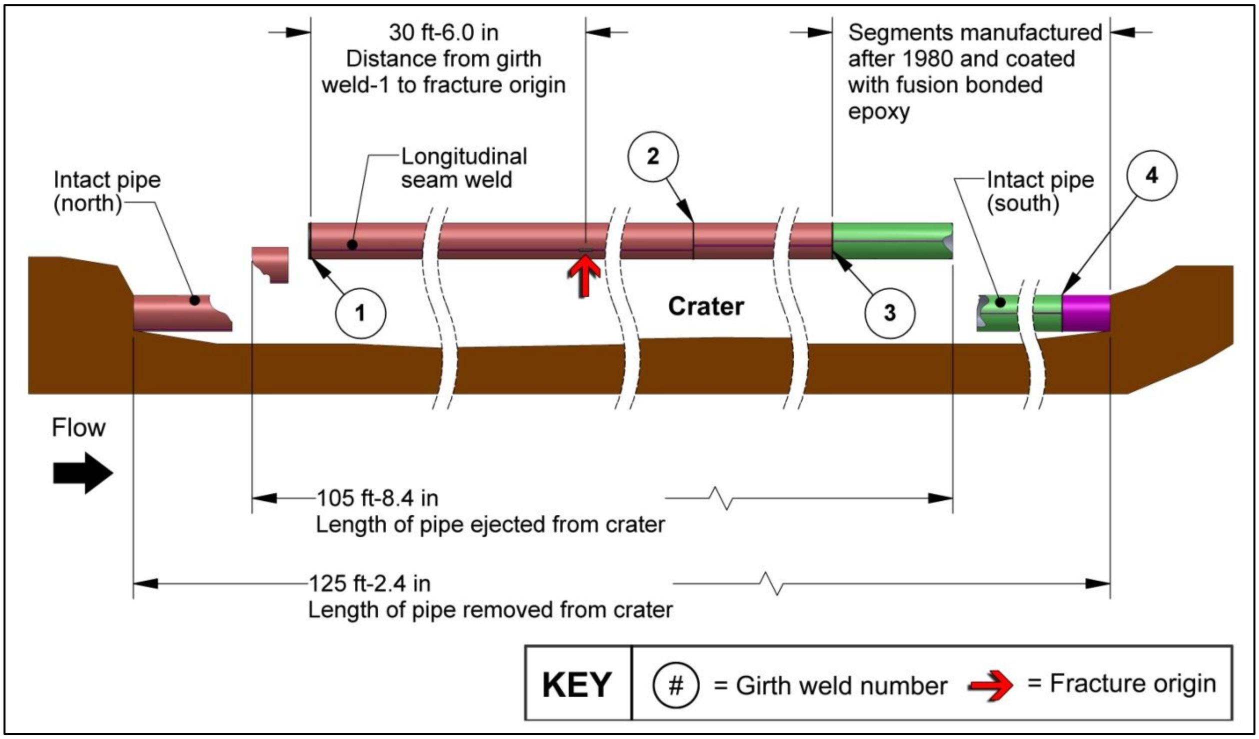

Figure 3. Side view of crater and four pipe segments of ruptured section.

Investigators examined SCADA pressure data from the upstream compressor station for the preceding year to identify the maximum operating pressure and operating ranges. The highest recorded pressure during this period was 865.4 psig, and the average operating pressure was about 850 psig. The largest daily low to high pressure range was 214 psig, with an average range of 36.7 psig.

Natural gas operators are required by 49 CFR Part 191 to report incidents involving leaks on transmission pipelines to the Pipeline and Hazardous Materials Safety Administration (PHMSA). Two FGT incident reports[15] identified failures caused by stress corrosion cracking (SCC)[16] on polyethylene-tape–coated pipelines in Florida and Alabama that were installed about 1959.

[14] *Cathodic protection* is a corrosion mitigation method used by the pipeline industry to protect underground steel structures. The system uses direct current power supplies at selected locations along the pipeline to supply protective electrical current. The protective current is supplied to the pipeline through a ground bed that typically contains a string of suitable anodes, with soil as an electrolyte. A wire connected to the pipeline provides the return path for the current to complete the circuit.

[15] PHMSA report numbers 19850184 (November 19, 1984) and 19850185 (February 25, 1985).

[16] *Stress corrosion cracking* is a form of environmentally assisted cracking produced under the combined action of corrosion and tensile stress typically manifesting as clusters of small cracks in the external body of the pipe.

Pipeline Configuration

Line 100 was one of three parallel, interconnected, or looped, pipelines operating along a 56.8-mile right-of-way. It transported natural gas north to south between compressor stations 20 and 21. (See figure 4.) The ruptured section was about 27.7 miles downstream of station 20. Branch connections from all three transmission lines delivered gas to many commercial and municipal customers between stations, including a Florida Power and Light power plant (Martin North). According to statements made by the pipeline controllers, it was normal to see a drop in pipeline pressure in the mornings and evenings when energy demand peaked. The 30-inch pipeline primarily operated as a loop, supplementing gas to the 18-inch and 24-inch transmission lines at the Jupiter regulating station through 12-inch-diameter cross-connections. Dual pressure-reducing regulators protected the lower MAOP on the 18-inch line from the higher MAOP on the 30-inch line.[17]

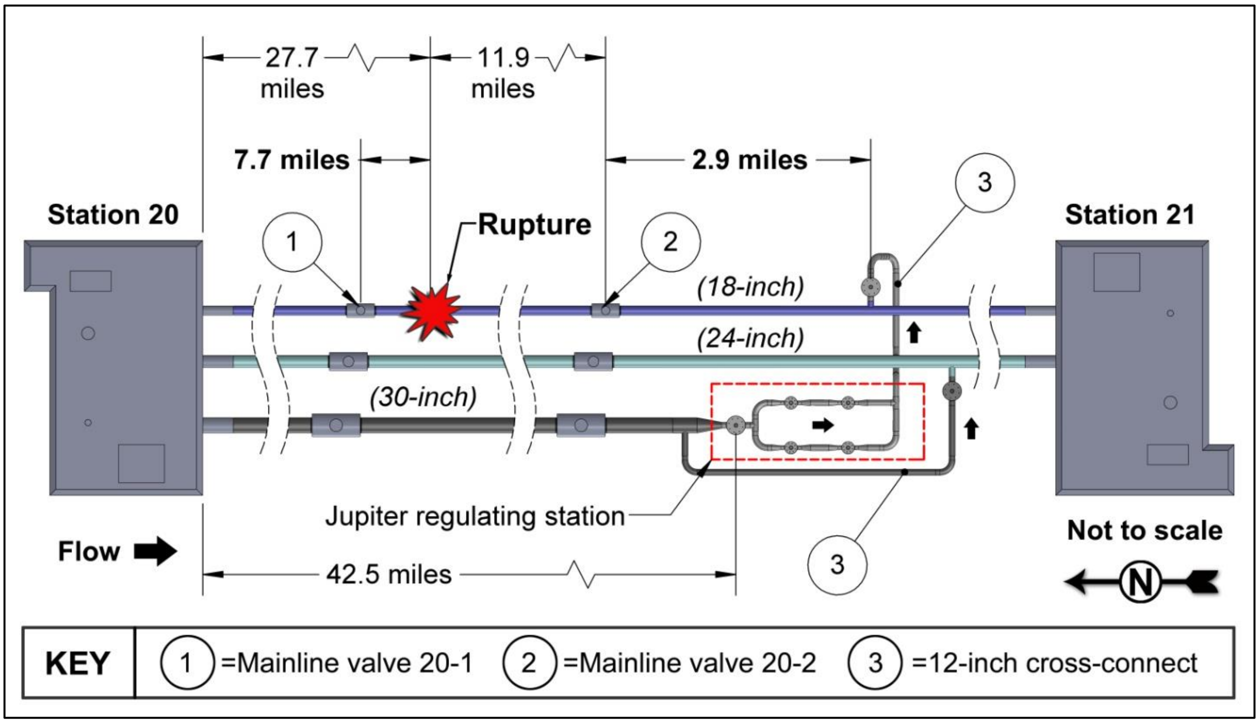

Figure 4. Simplified schematic of 18-inch, 24-inch, and 30-inch interconnected transmission lines between compressor stations 20 and 21.

ASV Line Break Actuators

The rupture occurred between ASV 20-1 and ASV 20-2 on the 18-inch main line. ASV 20-1 was about 8 miles upstream of the rupture site, and ASV 20-2 was about 12 miles downstream. ASV 20-2 was less than 3 miles from the 12-inch cross-connect joining the 30-inch and 18-inch pipelines. Both the 18-inch main line ASV and the 12-inch cross-connect ASV included line break actuators that automatically close the valves if a rupture or large leak occurs.

[17] The 18-inch pipeline was rated for a MAOP of 866 psig, and the 24- and 30-inch pipelines were both rated at a MAOP of 975 psig.

The line break actuators are designed to close the valve when the rate of pressure drop in the pipeline exceeds a predefined set point.[18] FGT stated that all of the line break actuators were identical in operation, including set points. The line break actuator on ASV 20-2 was set to trip at a pressure drop of 15.5 psig against an operating line pressure of 800 psig.

After the rupture, the upstream flow was stopped when the line break actuator at ASV 20-1 tripped and closed the valve about 2 minutes after the rupture, whereas the line break actuator downstream of the rupture at ASV 20-2 did not trip. ASV 20-2 was closed by hand by an FGT crew about 2 hours after the rupture. After the accident, FGT tested the line break actuator at ASV 20-2, and it tripped as intended at its design set point.

The FGT operations group performed yearly inspections and testing of the line break actuators to verify they operated properly. The manufacturer's service manual defines the relationship between rate of pressure drop and line pressure. If the rate of pressure drop is not steep enough, then the line break actuator may not trip. The line break actuator on ASV 20-1 did not trip when the line ruptured, most likely because the rate of pressure drop at the line break actuator was below the set point of the device. The limitations and design considerations for the use of line break actuators, including when they are installed in looped systems, are documented in a 1995 Southwest Research Institute report, *Remote and Automatic Main Line Valve Technology Assessment:*[19]

> Both field experience and simulation results show that rate of pressure drop measurements in looped lines are not as reliable for line break detection as in single line systems. Because flow from adjacent loops feed the ruptured line through open crossovers, pressure in the ruptured line does not fall as fast as it would if it were in a single line or if crossovers were closed.

SCADA System

When the pipeline ruptured, the SCADA pressure readings at the upstream compressor station showed a 24.3 psig drop[20] on the l8-inch line followed by steadily decreasing pressures in both the 30-inch and the 24-inch transmission lines.[21] The SCADA system reported the pressures at each compressor station and the stored volume of gas in the pipeline, but the system did not report intermediate pressure or flow readings[22] for the main line. None of the main line valves or cross-connect regulators included position feedback to SCADA. After the rupture, the controllers

[18] The line break actuator used pneumatic logic to compare the pressure in the pipeline to the pressure in a reserve cylinder. When the difference in pressure between the reserve cylinder and the pipeline meets a preset value, the actuator (gas over hydraulics) closes the mainline valve. Once tripped, the line break actuator has to be reset manually.

[19] C. R. Sparks et al., *Remote and Automatic Main Line Valve Technology Assessment,* Gas Research Institute Report No. GRI-95/0101 (Project No. 04-6609 for Gas Research Institute), (San Antonio: Southwest Research Institute, 1995).

[20] SCADA pressure readings from compressor station 20 showed a pressure drop between 5:10 a.m. and 5:12 a.m. from 853.8 psig to 829.5 psig.

[21] SCADA pressure readings at compressor station 20 showed a nearly identical pressure drop on the 24-inch and 30-inch pipelines from 899.7 psig to 813.8 psig between 5:17 a.m. and 7:07 a.m.

[22] Some branch connections to customer sites included pressure and flow readings that were viewable over SCADA and could be used by the control center to examine intermediate conditions.

did not know that ASV 20-1 had closed or that the cross-connect pressure regulators had fully opened.

Line 100 normally operated with frequent flow and pressure changes based on the demand for gas, and SCADA alarms were set to warn controllers about abnormal conditions. However, no SCADA alarms were triggered throughout this accident. The Monday morning shift controller stated that because SCADA showed no alarms, he did not examine the pressure drop or historical pressure trends until after the second call from emergency responders. The controller further stated that at the time of the accident, the drop in pressures on the three lines appeared to be consistent with peak demand and that, without an alarm, the pressure drop alone was not sufficient to suggest a leak or line rupture. FGT had incorporated both low- and high-pressure alarm settings and rate-of-change alarms set to detect abnormal operations that resulted from 20-psig pressure swings. Although none of the three pipeline pressures reached the low alarm threshold, the pressure change on the 18-inch line after the rupture was above the 20-psig threshold of the rate-of-change alarm.

A review of the SCADA rate-of-change alarm revealed that it did not trigger because of the upstream ASV closure and the SCADA scan rate. The rate-of-change alarm was programmed to alert the controller when a 20-psig difference from the previous recorded pressure was present over two scans of the pressure sensor (about 8 minutes at this location).[23] Pressure trend data from the accident indicate that the initial 24-psig drop at the upstream compressor station did not continue for two full scans of the SCADA system. When ASV 20-1 closed, the upstream pressure in the pipeline stabilized, resulting in a pressure difference less than 20 psig within the two scans, so the rate-of-change alarm did not activate.

Examination of the Accident Pipe

About 106 feet of pipe weighing about 5,000 pounds was ejected from the ground in two pieces. The larger of the two pieces measured about 104 feet long and was found opened up and folded over onto itself. (See figure 5.) The smaller piece measured 1.6 feet long and came to rest near the larger piece.

[23] FGT stated that the scan rate or time for SCADA to receive updated data from the instrumentation was about 4 minutes on this portion of the system.

Figure 5. One hundred four-foot-long section of 18-inch buried pipe that was dislodged from the ground.

Sample lengths of pipe were taken from each of the four segments of the ruptured section, including portions of the intact ends (upstream and downstream), and sent to the NTSB Materials Laboratory for testing and analysis. An examination of the fracture face showed that the rupture originated between girth welds 1 and 2 and simultaneously traveled upstream and downstream along the longitudinal seam welds through four girth welds. The fracture origin was about 30.5 feet downstream of girth weld 1 and was oriented in the 4 o'clock position[24] coinciding with the longitudinal seam weld. (See figure 3.)

Tape Coating, Corrosion, and Cracking

Examination of the Polyken 900 (polyethylene) tape revealed deterioration of the adhesive bond with the pipe surface, with preexisting wrinkles and air pockets or bubbles along the length of the ruptured section. Beneath the tape wrap, general corrosion and corrosion pitting were observed on the exterior surface of the pipe. Corrosion pitting damage was observed near the fracture and at regular 12-inch intervals where the overlapped spiral coating had disbonded from the pipe. The general and localized pitting corrosion indicated that the cathodic protection was ineffective in mitigating corrosion damage. Pitting corrosion, as deep as 0.075 inches (30 percent of the nominal wall thickness), was observed on or near longitudinal seam weld. The depth of the corrosion, measured at several locations near the origin, resulted in a remaining wall thickness that was less than the specified minimum. No internal corrosion was observed on the ruptured pipe section.

Magnetic particle inspections[25] conducted on the outer surface of the pipe along and adjacent to the fracture revealed several colonies of longitudinal cracks. (See figure 6.) These colonies of cracks were identified on both sides and close to the longitudinal seam weld.

[24] Orientation is given as the clockwise position when looking down the pipe in the direction of flow (north to south). The 12 o'clock position represents the top of the pipe.

[25] Magnetic particle inspection is a nondestructive test method for detecting the existence and extent of linear indications (such as cracks) open to the surface of ferromagnetic materials.

Additional colonies of cracks were found on the segment of pipe upstream from the rupture origin.

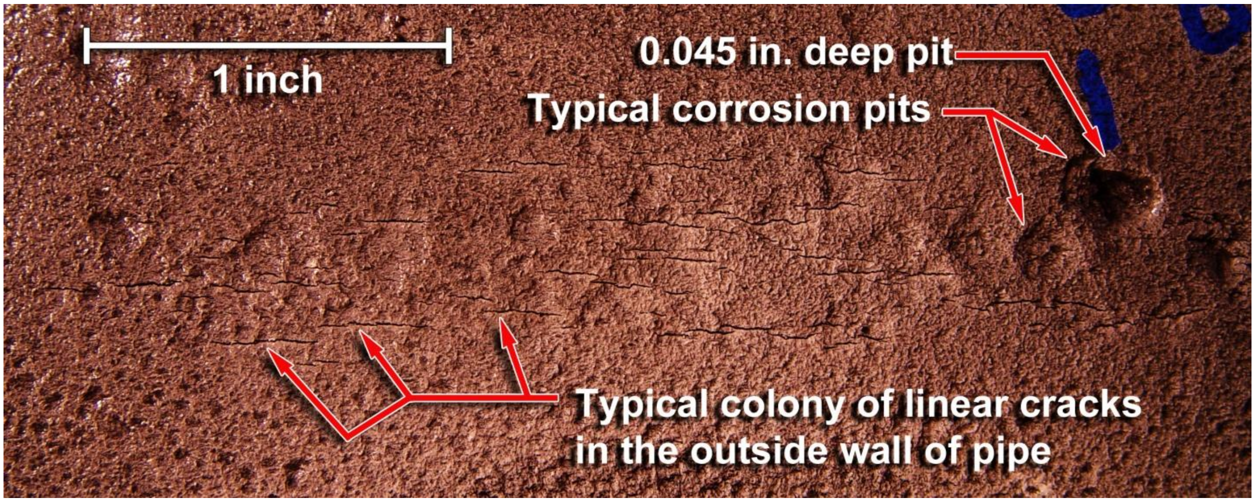

Figure 6. Longitudinal cracks and corrosion pits observed below longitudinal weld seam and upstream of rupture origin.

Further examination of the cracks revealed that they initiated from the bottom of corrosion pits on the external pipe surface. (See figure 7.) The initial stages of crack advancement into the pipe wall showed characteristics consistent with environmentally assisted mechanisms such as near-neutral pH stress corrosion cracking (NNpHSCC)[26] or corrosion fatigue.[27] Final stages of crack propagation in the pipe wall exhibited little secondary branching and was most consistent with NNpHSCC. NNpHSCC and corrosion fatigue are both forms of environmentally assisted cracking that share many similar metallurgical characteristics. According to the Canadian Energy Pipeline Association's *Stress Corrosion Cracking, Recommended Practices*, SCC occurs in pipelines with mechanically failed coatings in the absence of adequate cathodic protection.[28] The same publication indicated that pipe wrapped with polyethylene tape has the greatest susceptibility to SCC compared to all other coatings. The problem created by disbonded polyethylene coating and cathodic protection shielding is well known in the pipeline industry.[29]

[26] Near-neutral pH SCC is a specific form of environmentally assisted cracking that propagates through the metal grain boundaries with little secondary branching. It was first noted on the polyethylene-tape–coated pipeline in the TransCanada Pipelines system in the 1980s.

[27] Corrosion fatigue is a form of environmentally assisted cracking in materials under the combined actions of cyclic loading and a corrosive environment.

[28] *Stress Corrosion Cracking, Recommended Practices*, 2nd ed., (Calgary, Alberta: Canadian Energy Pipeline Association, 2007).

[29] Disbondment of the tape coating from the outer pipe wall can result in moisture ingress between the tape and the steel, promoting corrosion. In this instance, the polyethylene tape no longer separates the pipe wall from a corrosive environment and the high electrical resistance of the tape shields the surface from receiving the adequate protective current of the cathodic protection system.

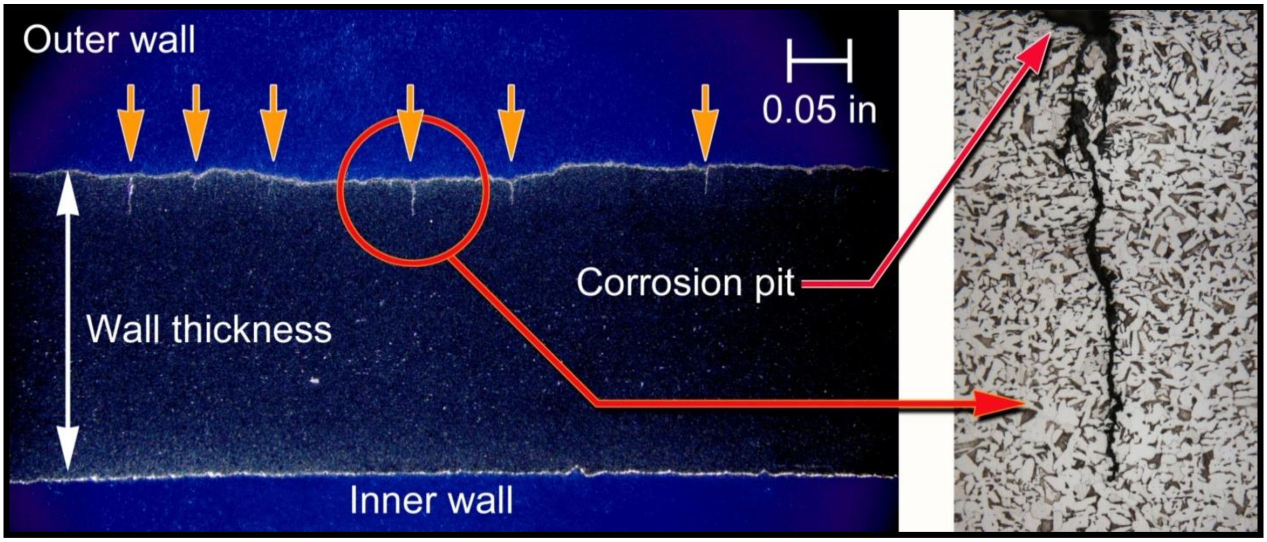

Figure 7. (Left) Cross section of colony of six longitudinal cracks (shown in figure 6) identified by arrows. (Right) magnified view of single crack (about 0.03 inches deep) advancing from corrosion pit.

The Fracture Origin

Fracture features on the face of the rupture identified the origin area, which measured about 6 inches long and was on the longitudinal weld seam. The longitudinal weld seam measured 0.255 inches thick in this region. The fracture face along the origin coincided with a dark colored region of corroded steel that extended from the outer surface of the pipe to a maximum depth of about 75 percent of the longitudinal seam weld thickness. (See figure 8.) No crack arrest features were observed on the fracture face. Two corrosion pits, about 1 inch apart, were on the outer surface in the corroded region of the fracture origin. Both corrosion pits measured about 0.2 inches in diameter and extended 0.04 inches into the pipe wall. Closer examination of the fracture surface near the two corrosion pits revealed radial marks emanating from the surface of the corroded region toward the inner wall. The corrosion pit at the deepest portion of the fracture origin included a subsurface crack that extended from the base of the pit. The fracture emanated from corrosion pits on the outer pipe wall and propagated toward the inner wall to a depth of 75 percent of the weld seam thickness before the remaining pipe wall failed from overstress.

The NTSB Materials Laboratory determined that the fracture most likely resulted from external environmentally assisted cracks along the longitudinal seam weld. The radial markings on the fracture face show that these cracks emanated from corrosion pits. The darker corroded region suggests that the crack propagation occurred over a long period before reaching a size that resulted in the rupture.

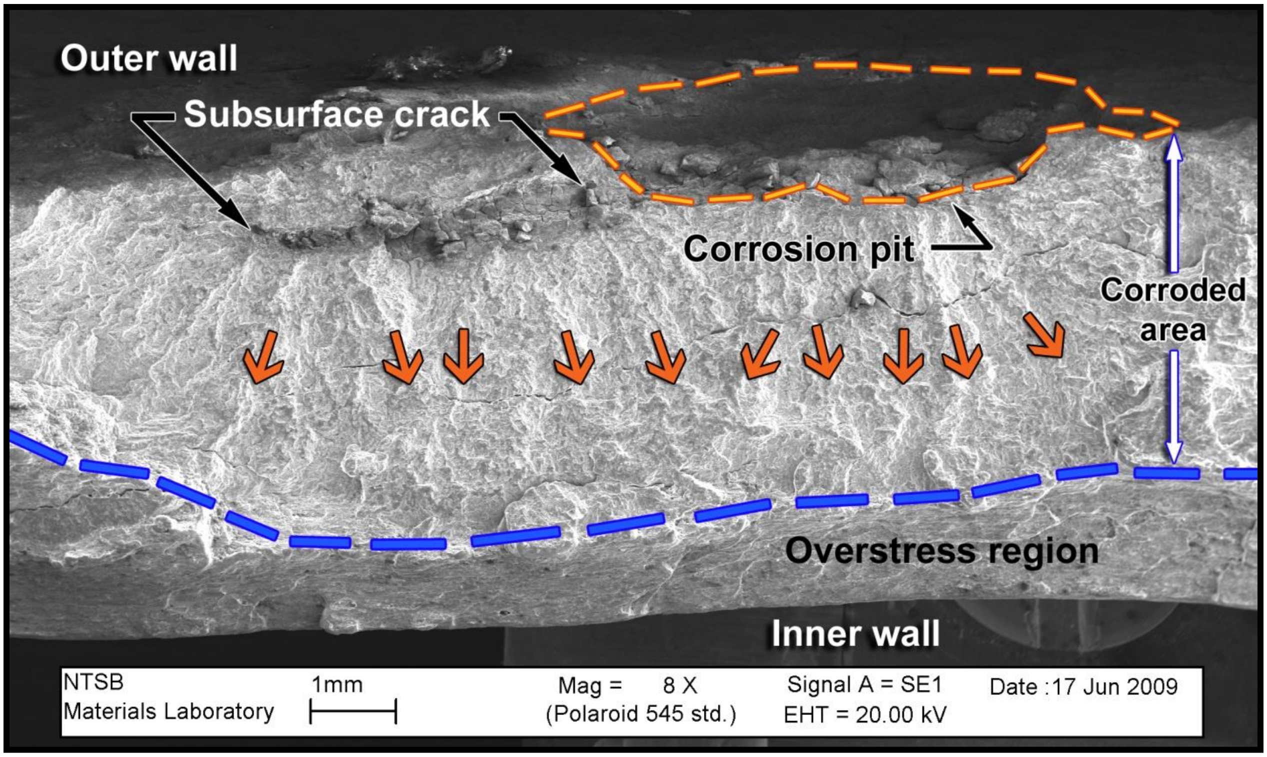

Figure 8. Scanning electron microscope photograph of a portion of the fracture origin showing corrosion pit at outer wall and subsurface crack.

Integrity Management

In January 2004, PHMSA issued the gas integrity management rule that established how pipeline operators should identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines using multiple assessment methods. This integrity management approach was directed at protecting high consequence areas (HCA) from catastrophic effects of ruptured natural gas lines. The integrity management rule required that a pipeline operator complete a baseline assessment of 50 percent of HCA pipeline mileage by December 17, 2007, and of 100 percent by December 17, 2012. As part of the integrity management program, an operator must identify and evaluate all potential threats to HCA segments, collect and integrate relevant data from the entire pipeline, and conduct a risk assessment in accordance with ASME B31.8S.[30]

Class Location

To determine which pipeline segments were covered under the integrity management rule, FGT used method 2, defined by 49 CFR 192.903,[31] to calculate a potential impact radius

[30] ASME B31.8S-2004, "Managing System Integrity of Gas Pipelines;" ASME Code for Pressure Piping, B31 supplement to ASME B31.8.

[31] "The area within a potential impact circle containing (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or (ii) an identified site."

and identify HCA sites within that radius. FGT reported more than 600 miles of HCA pipeline segments and 1,138 HCA locations covered under the integrity management program.

The ruptured section was defined by the integrity management group as being in a Class 1 location with no HCA identified sites.[32] Therefore, FGT did not include the pipeline section under the integrity management program. However, because HCA segments were located upstream and downstream of the rupture location, the entire 56.8 miles between compressor stations was inspected with in-line tools, including the pipe segments that ruptured, as part of the integrity management baseline assessment.

After the accident, a review of the area was conducted through PHMSA to examine whether a neighboring high school qualified as an HCA "identified site." The findings from the review concluded that the rupture location should have been designated as Class 3 and should have included an HCA identified site because the potential impact radius (366 feet) intersected three semi-open structures at the nearby high school.[33] (See figure 9.)

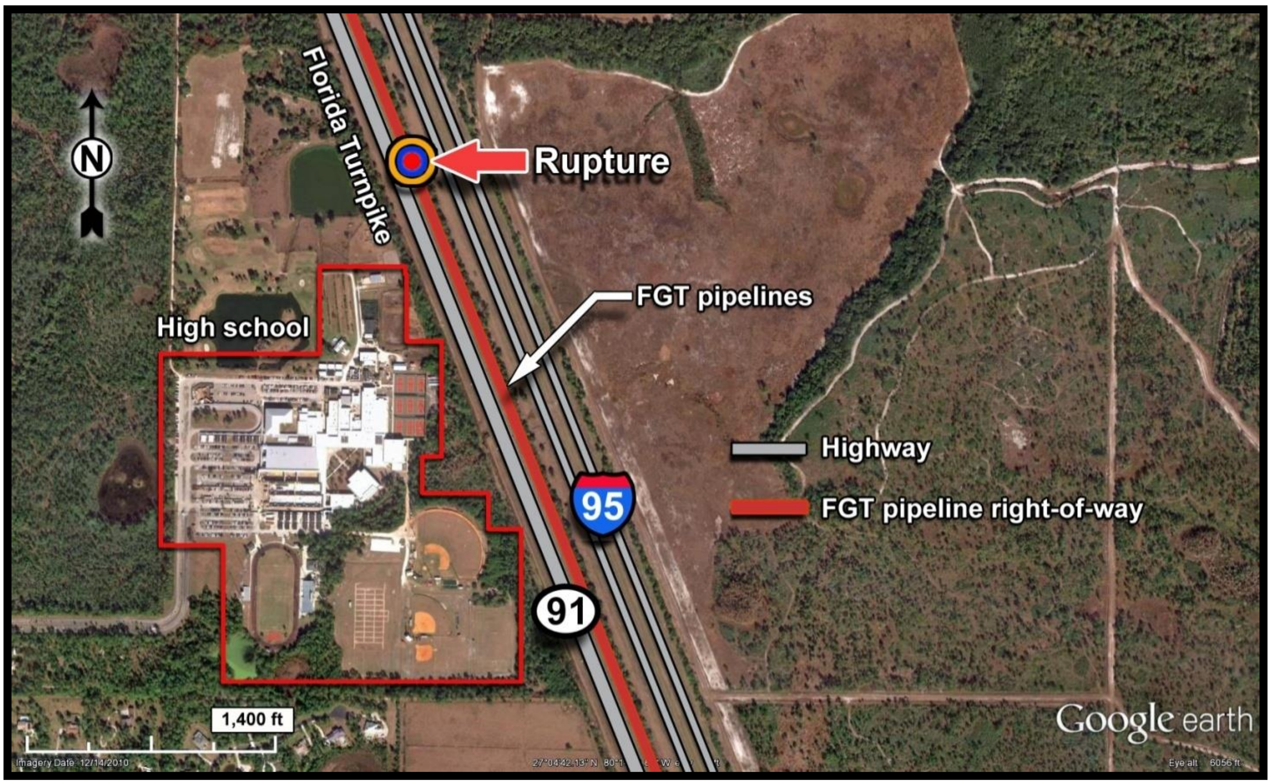

Figure 9. Rupture location shown relative to nearby high school that was determined to fall within 366-foot potential impact radius.

[32] The hydrostatic testing conducted in 1971 qualified line 100 for Class 3 operation; however, at the time of the accident, the ruptured section was operated as Class 1 by FGT.

[33] FGT did not reduce the mainline valve spacing from Class 1 to Class 3 to meet the requirements under 49 CFR 192.179, citing a PHMSA final ruling in the matter of Viking Gas Transmission (1998; CPF 32102). Because the class change did not require pipe replacement, no mainline valves were required.

Integrity Assessments

The FGT risk assessment program in place in 2004[34] used a total risk methodology addressing the nine threat categories described in ASME B31.8S and classified threats as either time dependent, stable, or time independent. Time-dependent threats include external corrosion and SCC. The total risk was defined as the product of the likelihood of an event multiplied by the consequence of that event. The likelihood of failure was derived using appendix A of ASME B31.8S and an internally developed consequence algorithm. The program used a prescriptive method combined with subject matter expert input to arrive at the total risk value.

The FGT risk assessment procedure stated that the threat of SCC is managed by external surface coating systems, balanced cathodic protection, minimizing cyclic loading, and operating below 60 percent specified minimum yield strength (SMYS) (if possible). The procedure noted that in-line inspection tool effectiveness[35] for detecting SCC had not been adequately demonstrated for gas lines, but the procedure outlined other methods that could be used to assess susceptibility to SCC, including soil characterization, magnetic particle inspection, pressure testing, and leak and rupture history.

The FGT 2004 risk assessment spreadsheet showed that the pipeline segments upstream and downstream of the rupture location had very low risk scores for both the external corrosion and the SCC categories.[36] According to the FGT corrosion engineer, polyethylene-tape–coated pipe has the highest risk weighting for SCC, but pipeline segments along the Florida peninsula had no prior history of SCC-related failures.

When SCC was identified as a risk in the relative risk matrix, the FGT 2004 integrity assessment procedures discussed the use of both direct assessment and hydrostatic spike pressure testing.[37] FGT stated that hydrostatic spike testing was the approach used for SCC and that direct assessment was not part of the integrity program.

Appendix A of the 2004 FGT integrity assessment procedure states that the use of spike testing is the method of choice when confirmed “significant” SCC[38] is present and a proven EMAT tool[39] is not commercially available. Without a direct assessment program, the FGT

[34] FGT risk and integrity procedures were Cross Country Energy procedures from 2004 until 2006 when the company was sold to Southern Union Gas (Panhandle Eastern).

[35] The FGT integrity assessment procedure lists the electromagnetic acoustic transducer (EMAT) and the circumferential magnetic flux leakage (MFL) in-line inspection tools as being capable of SCC detection, but each has limitations on detection capabilities. FGT had not run an EMAT or circumferential MFL tool through line 100 before the rupture.

[36] External corrosion relative risk assessment scores were 0.03 for upstream HCA segments and 0.05 for downstream HCA segments. SCC relative risk assessment scores were 0.001 for upstream HCA segments and 0.003 for downstream HCA segments.

[37] The FGT procedures define the spike test as a 30- to 60-minute pressure test to 100 to 110 percent of SMYS followed by a reduction to 90 percent of SMYS pressure for the remainder of the test.

[38] Defined by FGT as deeper than 10 percent of the wall thickness and as long or longer than the critical crack length of a crack 50 percent through the pipe wall at a stress level of 110 percent of SMYS as defined by the Canadian Energy Pipeline Association.

[39] The EMAT tool is designed to detect crack defects using electromagnetic acoustical transducers. These dry coupled sensors do not require a liquid couplant like traditional ultrasonic crack detection tools, making the EMAT tool suitable for gas pipeline inspections.

identification of SCC as a threat relied primarily on historical failures or findings from opportunistic digs. According to the FGT director of integrity management, the ruptured section had not been identified as susceptible to SCC and therefore was never spike tested.

Line 100 In-line Inspections

In-line inspections were performed on line 100 in 2004 using both a caliper tool to locate dents and a high-resolution second-generation axial MFL tool to locate metal loss caused by corrosion. Although axial MFL in-line inspection tools are well suited for detecting metal loss features in pipelines, they are incapable of accurately detecting longitudinally oriented defects, including colonies of SCC.

The findings from the 2004 axial MFL in-line inspection of line 100 revealed that most of the surface indications were adjacent to the longitudinal seam weld. The inspection identified no corrosion anomalies at the location of the rupture origin. The 2004 MFL final report recorded maximum corrosion depths of between 0.04 and 0.1 inches at various locations along the ruptured section; the average peak depth was about 0.051 inches (20 percent of the nominal wall thickness). None of the reported corrosion anomalies met the immediate criteria for repair. Based on the findings of the 2004 in-line inspection, FGT performed 12 excavations, all of which were on pipeline segments between compressor stations 20 and 21. None of these excavations exposed the ruptured segment. FGT also replaced two segments of pipe downstream from the failure origin and girth weld 3 (see figure 3). FGT could not provide supporting documentation from the 2004 in-line inspection that led to the replacement of the two pipe segments.

Postaccident Actions

PHMSA

After the accident in Palm City, PHMSA issued a corrective action order (CAO) to FGT on May 7, 2009; PHMSA later amended the CAO on May 22, 2009. As part of the CAO, FGT was not allowed to operate line 100 until a written plan to verify the integrity of the pipeline segments was approved by the PHMSA regional director. Pipe segments from compressor station 20 through Cutler, Florida, were subject to the verification, which required hydrostatic spike testing of all low-frequency ERW pipe, the use of the appropriate in-line tools suitable for finding defects such as the one responsible for the rupture, an evaluation of the pipeline for areas of damaged or disbonded coating, and a survey of the effectiveness of the cathodic protection system. When permission to restart the line was granted by the PHMSA director of the Southern Region on June 2, 2009, the portion of line 100 from compressor station 20 to Cutler, Florida, was subject to a 20 percent reduction in operating pressure, not to exceed 682 psig. FGT submitted a return–to-service plan to PHMSA on May 27, 2009 and FGT had restarted line 100 by June 3, 2009.

Florida Gas Transmission

After the accident, FGT reviewed all locations on the pipeline system that had a cross-connect arrangement similar to that of the accident location. Six looped configurations similar to the accident site were identified for instrumentation upgrades. FGT installed a pressure transmitter downstream of the regulators at the Jupiter regulator station and pressure transmitters on each of the parallel lines.

Position sensors were also installed on both regulators, allowing the control center to monitor the regulating valve states, and a proximity sensor was installed on the cross-connect valve. Each of these sensors was tied into the SCADA system. Additional functionality was added to the SCADA system so that the cross-connect valve between the 30-inch and the 18-inch pipelines would close automatically if a rapid change in the position of the regulator valve occurred. This added functionality also permits the control center to close the cross-connect valve remotely. A proximity switch on the cross-connect valve now activates to alert the control center when the line break actuator trips and the valve closes.

FGT has changed the SCADA rate-of-change alarm methodology. SCADA now alarms for a rate-of-change equivalent to a pressure drop of more than 32 psig over a 120-second interval. FGT also conducted an instrument gas leak survey between compressor stations 20 and 21 and increased leak inspection land patrols of the transmission line downstream of the accident site to the end of the line. These patrols are in addition to aerial patrols.

In response to the PHMSA corrective action order, FGT has conducted cathodic protection surveys on line 100 from compressor station 20 to the end of the line, inspected the line for corrosion using a magnetic flux leakage tool and for SCC using circumferential MFL, and conducted hydrostatic pressure testing of the 56.8-mile stretch between compressor stations 20 and 21. According to FGT, the hydrostatic pressure testing resulted in four failures on the 18-inch line: (1) a failure caused by corrosion in an ERW longitudinal weld seam, (2) a seam failure related to SCC, (3) a failure caused by corrosion, and (4) a failure caused by mechanical damage. FGT has performed a subsequent hydrostatic spike test on the segments from compressor station 20 to ASV 20-2.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the accident was environmentally assisted cracking under a disbonded polyethylene coating that remained undetected by the integrity management program. Contributing to the accident was Florida Gas Transmission Company’s failure to include the pipe section that ruptured in the integrity management program. Contributing to the prolonged gas release was the pipeline controller’s inability to detect the rupture because of SCADA system limitations and the configuration of the pipeline.

Adopted: August 13, 2013