How the Office of Pipeline Safety utilizes in-line inspection results

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HOW THE OFFICE OF PIPELINE SAFETY UTILIZES IN-LINE INSPECTION (ILI) RESULTS

INTRODUCTION

The Office of Pipeline Safety (OPS), a part of the Department of Transportation's Research and Special Programs Administration, administers the Department's national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. Under this program, OPS develops and enforces regulations as well as other approaches to risk management, to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. A major aspect of assuring pipeline safety is a sound, comprehensive, compliance program, conducted by the OPS regional offices and participating State agencies. In addition to conducting inspections of pipeline operators, a key function of the regional offices, is to investigate major pipeline accidents to determine whether violations of regulations occurred or whether revisions or additions to the regulations are needed. In addition to ascertaining the cause of an accident, an objective of an OPS investigation is to determine whether remedial actions are necessary to help assure the pipeline's integrity. For further information regarding OPS's enforcement and compliance authority, please refer to the Pipeline Safety Regulations, Title 49, CFR, Part 190.

An in-line inspection (ILI) pig is a device which passes through a pipeline usually propelled by the commodity being transported. It can detect certain anomalies in the pipeline and record the location and relative severity of the anomaly through a recording device (such as a magnetic tape) operated by an on-board power source (i.e. a battery). The ILI pigs are useful for identifying certain anomalies in the pipeline. OPS recognizes certain limitations each ILI pig may have in locating specific types of anomaly, and that different types of ILI pigs are designed to find specific types of anomalies.

After a major accident, the overall pipeline integrity often comes into question. All parties including the public, Federal regulatory agencies, state and local governments, and the pipeline operator do not want a recurrence of the accident. After the area affected by the accident has been made safe, the most important issue for OPS and the pipeline operator to resolve is establishing the integrity of the pipeline and reassuring the public that the pipeline can be returned to service and operate safely. In the past, OPS relied mostly on having pipeline operators hydrostatically test affected portions of their pipeline to help assure the integrity. In recent years, OPS has accepted ILI pigging technology and pigging results as an alternative to hydrostatic testing of pipeline for specific types of failures. Generally, ILI inspection tools were used to find corrosion, wall thinning,
and dents. Recently, OPS has allowed and is currently evaluating a British Gas ILI pig (a prototype experimental elastic-wave ultrasonic tool) being utilized on Colonial Pipeline’s facilities, to find cracks in or adjacent to longitudinal weld seams. If OPS accepts the results, Colonial Pipeline will not be required to perform a hydrostatic test of this portion of it pipeline.

This paper describes how OPS, working with the pipeline operators, has applied ILI technology after accidents. Obviously, different types of ILI pigs were used to carry out different missions. In several cases, a combination of ILI pigs were used. After an accident, when OPS issues an Order or enters into an Agreement, OPS normally requires the operator involved to develop and submit a specific ILI pig plan for OPS review and approval. The ILI pig plan provides details of types of pigs proposed to be run, how anomalies will be identified, non-destructive examination (NDE) criteria to be used to evaluate anomalies and other techniques, as applicable, to show the effectiveness of the ILI pig run(s). OPS also requires the pipeline operator to submit a validation procedure. The acceptance of ILI pig run(s) and associated remedial work is subject to concurrence by an OPS Regional Director.

BACKGROUND

OPS first became actively involved with the ILI tools, or smart pigs, in the early 1970s in connection with the construction of Trans-Alaska pipeline. Although there is no Federal requirement to utilize ILI pigs, OPS has utilized ILI pigs in selected compliance cases as a tool to validate the pipeline integrity after major accidents.

To date, OPS has not issued regulations requiring in-line inspection of pipelines. The only ILI regulation OPS has published (Final Rule - April 12, 1994) required new gas transmission and hazardous-liquid pipelines and components to be designed and constructed to accommodate ILI pigs. This regulation also required, for each line section of a pipeline, valve, fitting, or other line component replaced, to be designed and constructed to accommodate the passage of ILI tools. This regulation has been controversial in the gas-transmission-pipeline industry. The enforcement of this Final Rule with respect to modifications allowing use of ILI pigs for entire line sections in onshore gas transmission lines and new and existing offshore gas transmission lines was suspended as a result of a Petition by the Interstate Natural Gas Association of America. This suspension will remain in effect until OPS evaluates comments on the Final Rule and publishes new compliance dates in a subsequent rule making.

While OPS continues to encourage the use of ILI pigs, OPS realizes that almost all ILI smart pigging that has been performed was done on a voluntary basis by the pipeline industry. OPS through Title 49, CFR, Part 190, Enforcement Procedures, nevertheless, starting as early as 1986, has required pipeline operators, on a selected basis, to use ILI pigs to help assure pipeline integrity after major pipeline accidents.

The term ‘ILI pig’ may have different meanings throughout the pipeline industry, but for the purpose of this paper, an ‘ILI pig’ refers to any type of in-line inspection device capable of detecting pipeline anomalies such as dents, ovality, gouges, cracks, corrosion, and metal loss. Table A below provides a listing of various types of ILI pigs that have been utilized by pipeline operators under OPS Orders or Agreements.

SELECTED CASE HISTORIES

In this Paper, I have selected cases about pipeline accidents where OPS required and accepted a Pipeline Operator’s ILI pig plan and associated remediation plan. Included is the operator’s name, date(s) of accident(s), location of accident, pipe material data, cause of failure, type and purpose of ILI pig(s) used, and results of the pigging. In the cases described, OPS accepted the pigging results which re-established pipeline integrity, which usually lead to full resumption of normal pipeline operations. In all cases, the pipeline operator was required to substantiate, by careful
engineering evaluation, analysis of ILI pig data, and examination of pipe at the associated excavation sites, that the integrity of a pipeline was re-established before resumption of normal pipeline operation.

**Texas Eastern Transmission Corp (TETCO) accidents in Kentucky, 1985 and 1986**

**Background**

Texas Eastern Transmission Corp (TETCO) has had two major accidents on 30-in diameter gas transmission pipelines (Line #10 and #15) in Kentucky due to external corrosion. The pipe involved in both accidents was API 5LX, Grade X-52, 0.375-in w.t., manufactured by Republic Steel and Claymont Steel, installed in 1957. These two accidents lead to an OPS Consent Order requiring a rehabilitation plan for TETCO in the State of Kentucky. This was the first time OPS required an ILI smart pig program by an Order.

**Accident of April 27, 1985**

The first accident occurred on April 27, 1985, near Beaumont, Kentucky, on the 30-in gas transmission pipeline (Line #10) in a steel casing which crossed a state highway. This failure resulted in a 30-foot rupture of the pipeline creating a large crater across the highway. Five people were killed and three were injured as a result of this accident. The property damage cost resulting from this accident was estimated to be $8.4 million. The cause of failure was attributed to undetected atmospheric corrosion on the pipe inside the casing. As a result of this accident, TETCO initiated an intense ILI pig program for Lines #10, #15, and #25 in Kentucky.

**Accident of February 21, 1986**

The second accident occurred on February 21, 1986, near Lancaster, Kentucky. Escaping gas ignited and resulted in three injuries and extensive property damage. The cause of the failure was external corrosion on the 30-in gas transmission line (Line #15). This failure occurred nearly five months after a standard MFL pig survey had been completed. The MFL pig had identified an area of significant wall thinning. As a result TETCO partially exposed the pipeline to verify the indication of corrosion identified by MFL pig. After the location was verified, and the pipe was inspected, the corroded section was cleaned and recoated, and the length of pipe was backfilled. However, the pipe wall was not longer sufficient for the maximum allowable operating pressure (MAOP), but the pressure was not lowered nor was the pipe repaired. The failure to determine if the remaining wall thickness was adequate for the MAOP or to replace the pipe as required by the Pipeline Safety Regulations was due to personnel not following the Company procedures. The corrosion occurred in an area where the cathodic protection readings did not indicate a problem. However, it is likely that the pipe failure point was shielded from protective cathodic protection current by a rock stratum adjacent to the pipe.

As a result of our investigation of these failures, OPS issued a Consent Order requiring a 10% reduction of pressure for Lines #10, #15, and #25 in the State of Kentucky from the MAOP that existed before the February 21, 1986, accident. TETCO was also required to submit a Rehabilitation Plan to OPS which included an ILI program for the above lines. OPS, because of the newness of the MFL tool technology, required TETCO to prove the effectiveness of the ILI inspection and repair program. TETCO was required to hydrostatically test over 150 miles of pipe downstream from its compressor stations, after repairs required by the ILI survey had been made.

TETCO reported that it ran the Tuboscope ILI MFL tool for a total of 685 miles in its 30-in and 36-in pipelines within the State of Kentucky. As a result, TETCO reported 1,475 pipe excavations...
were performed and over 1,100 pipe sections were replaced. This massive effort illustrated to OPS and state officials in Kentucky, the effectiveness and benefits of conducting MFL surveys. OPS allowed the original pressure to be restored upon completion of the above program.

Colonial Pipeline Co

Colonial operates large-diameter petroleum-product pipelines between Texas and the New Jersey/New York City area. OPS and Colonial have utilized ILI pigs to help resolve the integrity issues regarding Colonial's pipeline in the Mid-Atlantic States. ILI pigs have been, and are continuing to be, utilized by Colonial to find the following: (1) cracks in or adjacent to the longitudinal seam weld; (2) dents/mechanical damage; and (3) corrosion.

Colonial Pipeline, cracks in longitudinal welded seams, Locust Grove, Virginia, 1989

The first Colonial issue this paper will address deals with "cracks in or adjacent to the longitudinal seam" found in the double-submerged-arc-welded (DSAW) pipe with a high diameter to wall thickness ratio (D/t), manufactured by National Tube Division of US Steel Corp. These cracks were formed during railroad transportation in the early 1960s, and grew during the pipeline operations. There have been two in-service longitudinal crack seam failures in Virginia. Both occurred in Colonial's pipeline on Line #4. This pipeline is 32-in diameter, 0.281-in w.t., API-5L, Grade X-52, DSAW pipe, manufactured by the National Tube Division of US Steel Corp, and was installed in 1963. The diameter to wall thickness ratio (D/t) of this pipe is 114.

Accident of December 18, 1989

The most recent accident on Colonial's Line #4 pipeline occurred on December 18, 1989, one mile north of its Locust Grove Pumping Station in Orange County, Virginia. The pipeline rupture resulted in a release of about 212,000 gallons of kerosene spilling into Mine Run Creek, a tributary of the Rapidan River. This failure, occurred about 3 miles from an earlier longitudinal seam crack failure which had occurred on March 6, 1980. Unfortunately, the City of Fredericksburg, Virginia, temporarily lost its source of water supply as a result of each spill. The cause of both failures was fatigue cracks initiated in or adjacent to the longitudinal seam of the pipeline when the pipe was transported by the railroad. These cracks later grew during the pipeline operation. After the December 18, 1989 accident, OPS entered into a Formal Testing Agreement with Colonial Pipeline requiring a pressure reduction and hydrostatic test program for the portion of the pipeline in Virginia and Maryland that had National Tube pipe.

The hydrostatic test was conducted in 1990 to a minimum test pressure of 100% of specified minimum yield strength (SMYS) at the lowest elevation, and 85% SMYS at the highest elevation in each test section. The test was maintained for a period of eight hours. Colonial blew out only one additional longitudinal seam fatigue crack during the hydrostatic test. The pipe failed at a test pressure higher than the normal operating pressure.

Additionally, as a part of the Agreement, Colonial agreed to conduct an Operational Reliability Assessment (ORA) of its Line #4 located between Greensboro, North Carolina, and Dorsey Junction, Maryland. The ORA included PIPELINE calculations based on longitudinal seam cracks that could survive the 1990 hydrostatic test and based on pipeline normal operating parameters. The ORA concluded that in the third quarter of 1995 a new hydrostatic test should be initiated for the sections of Line #4 containing the National Tube pipe downstream of the Remington Pump Station in Virginia or, if available, inspect the pipeline with ILI pig capable of finding cracks in or adjacent to longitudinal weld seams.

In 1995, Colonial concluded that British Gas had developed an ILI pig capable of finding cracks in or adjacent to longitudinal weld seams. British Gas had stated that it was confident that it could find longitudinal weld seam cracks equal to or greater than 2.5in in length and 25% through pipe wall. A crack of this size is much smaller than a crack which would fail during a hydrostatic test similar to the one conducted in 1990. Colonial ran the elastic-wave ultrasonic British Gas tool to find cracks in or adjacent to longitudinal weld seams in its pipeline for a 40-mile section, north of
its Remington pump station, in the spring and early summer of 1995. British Gas interpreted the pig data and used three categories to identify crack class:

C-1 - definite crack characteristics
C-2 - some crack characteristics but not all
C-3 - indication of unknown anomaly (but no cracks)

As of December 31, 1995, British Gas had identified 27 cracks or crack like features (16 C-1, 6 C-2, and 5 C-3) along longitudinal weld seams in Colonial's Line #4 in the 40-mile pig run using ILI pig. As of December 31, 1995, Colonial has exposed all 27 cracks or crack-like features.

Colonial performed an on-site evaluation and confirmation of these anomalies by NDE techniques (such as ultrasonic and/or eddy current) to confirm and demonstrate the effectiveness of ILI pig run. Colonial also has had destructive testing of several cracks performed by a metallurgical laboratory to verify field measurements. At the time of this paper, British Gas and Colonial are continuing to analyze the ILI pig data. Final results will be submitted to OPS for review and acceptance. The 'preliminary' results are encouraging because there has been a very good correlation between British Gas analysis of the pig data and the measured results done by field excavations.

Colonial Pipeline Accident, Reston, Virginia, 1993

The second Colonial integrity issue where ILI pigs were utilized was on its Line #3, which involved mechanical damage, dents, and gouges. These concerns were highlighted by the failure of Colonial's 36-in diameter pipeline in Reston, Virginia.

On March 28, 1993, Colonial's 36-in (Line #3) petroleum-products pipeline failed in Reston, Fairfax County, Virginia. This pipe was manufactured by Republic Steel, Grade X-52, 0.344-in w.t., installed in 1980. The diameter to wall thickness ratio (D/Di) of the pipe was 105. The pipe failed in an area of gouges and dents on top of pipe caused by mechanical damage. This failure resulted in a spill of about 336,000 gallons of No.2 fuel oil into Sugarland Run Creek, a tributary of the Potomac River. Some of the product did reach the Potomac River which caused the incident to receive national attention. OPS issued a Hazardous Facility Order (HFO) requiring exposure and examination of pipe adjacent to the failure and ordered a pressure reduction restriction to 50% of Colonial's maximum operating pressure (MOP) between Chantilly, Virginia, and Dorsey Junction, Maryland. Colonial was also ordered by the HFO to submit a plan for internal instrumented inspection between Chantilly, Virginia, and Dorsey Junction, Maryland, to locate similar dents and gouges found at the Reston accident site.

The pipe ruptured at the 11:30 o'clock position on the pipeline. For a detailed description of the metallurgy of pipe, and measurements of gouges and dents associated with the failed pipe, refer to NTSB-Metallurgist's Factual Report (Attachment 1).

When Colonial exposed additional pipe adjacent to the rupture, dents were found on the bottom of the pipe, including a dent located 28 ft from the rupture site that was 2% of the diameter of the pipe (0.72 in depth) that contained what appeared to be a gouge. The challenge in coming up with an appropriate ILI plan was that it needed to be able to find dents that could contain a longitudinally-oriented gouge similar to those found at the rupture site. OPS accepted an ILI plan that required Colonial to conduct two ILI pig runs using two different types of tools. Colonial utilized a Vetco slope/deforation pig and a Vetco standard MFL tool. The plan accepted by OPS required Colonial to expose all anomalies on the upper quadrant of pipe and all dents greater than 2% on the rest of the pipe. In addition, Colonial and Vetco were required to identify all anomalies using data from both the deformation and MFL tools which indicated a longitudinal dent or depression of at least 3 in length or that otherwise may indicate the presence of a longitudinally-oriented gouge. Wall thinning (Vetco Grade 2 and 3) anomalies indicated by the magnetic pig were also required to be excavated and examined.

After analyzing the combination of magnetic and deformation pig data, all anomalies identified as possible longitudinally-oriented gouges or dents were excavated, examined, and evaluated. All dents were required to be examined using wet magnetic particle (wet-mag) inspection and ultrasonics. As a result of the above, Colonial performed 124 pipe excavations.
How the OPS utilizes ILI results

A breakdown of the anomalies found is shown below:

- dents/flats spots: 75
- bending shoe marks: 12
- misc. defects: 27 - (includes 2 buckles)
- mill defects: 11
- possible mechanical damage: 4

Forty-two anomalies were in an upper quadrant of the pipe, and of those, four appeared to be caused by outside mechanical equipment. A total of 11 segments of pipe were repaired with full-encirclement welded sleeves, and two segments of pipe were replaced. All four mechanical-damaged anomalies were repaired with full-encirclement welded sleeves (one of these was later cut out). Seven full-encirclement welded sleeves were used to repair dents with scratches or gouges found on the bottom of the pipe. The scratches and gouges were caused by rocks. The buckles found were cut out.

OPS and Colonial are confident that this inspection program was a success, and would have found any dents or gouges in the pipeline similar to those found at the failure site. Subsequently, Colonial was allowed to raise the pressure to 80% of the pipeline's MOP. At this time, the pressure restriction of 80% of the MOP remains in place. Colonial is now actively working on a similar ILI inspection program for Line #3 from Greensboro, North Carolina, to Chantilly, Virginia.

Colonial Pipeline (Line #4) - other accidents

There has been a great interest regarding the integrity of the Colonial pipelines in Virginia, particularly with Fairfax County, the City of Fredericksburg, and the State's Congressional delegations. The third integrity issue deals with corrosion, dents, and rock damage on Colonial's 32-in (Line #4) pipeline. Colonial has reported to OPS three leaks caused by rocks on its Line #4 in Virginia over its lifetime. This line has experienced outside force damage over its lifetime.

Accident of March 6, 1980

Colonial, in addition to the incidents described earlier, has had two other major failures on its 32-in (Line #4) pipeline in Virginia. On March 6, 1980, Line #4 failed at two different locations. Near Manassas, Virginia, the pipeline failed because of a pressure surge resulting from an unexpected shutdown of the pump station which caused the pipe to fail at a point where the pipe wall was thinned by corrosion at the road crossing casing. The rupture resulted in the release of about 336,000 gallons of aviation kerosene into Bull Run, a tributary of the Occoquan Reservoir, a major source of water supply for Northern Virginia.

On that same date, the 32-in pipeline also failed at a longitudinal seam crack near Locust Grove, Virginia. This resulted in a spill of about 92,000 gallons of No.2 fuel oil into the Rapidan and Rappahannock Rivers, causing the City of Fredericksburg to shut-in its water supply. This failure was also referenced above in this paper. Both these failures were triggered by a pressure surge from an incorrect pump shutdown.

Colonial Pipeline wrap up-ILI pigging programs

I will not attempt to go into all the OPS considerations and activities regarding Colonial Pipeline in the Mid-Atlantic States region. However, it was the goal of OPS, because of past accident history, state and local community interest, and the success of previous ILI pig programs implemented by Colonial, to enter into one Consent Order which would require Colonial to perform an ILI program for all its main trunk lines from Greensboro, North Carolina, to Dorsey Junction, Maryland. OPS also wanted to include Colonial's ongoing program for finding longitudinal seam cracks under the same Consent Order. The objective was to put all Colonial's ILI pigging requirements ordered by OPS, under one Order to simplify tracking of progress by Colonial, OPS, and state and local officials. This was accomplished on August 15, 1995, when Colonial and OPS entered into a Consent Order.
Texas Eastern Transmission Corp (TETCO) accident, Edison, New Jersey - 1994

On March 23, 1994, a failure occurred on TETCO's 36-in diameter gas transmission (Line #20) at the asphalt plant yard in Edison, New Jersey. The pipe involved is API 5L, Grade X-52, 0.675-in w.t., manufactured by Bethlehem Steel, and was installed in 1961. The rupture resulted in an explosion and fireball of up to 400 to 500ft high. It caused minor injuries to over 100 people, and in-patient hospitalization of two people. It destroyed eight apartment buildings and approximately 1,500 apartment residents were evacuated, many of whom lost their homes. The incident received extensive media coverage. Based on the National Transportation Safety Board (NTSB) Pipeline Accident Report of 1994, the estimated property damage from the accident exceeded $25 million.

According to NTSB, the probable cause of the pipe rupture was mechanical damage to the exterior surface of the pipe that reduced the wall thickness and likely created a crack in a gouge that grew over time. The NTSB determined that the gouge which failed was located at the 1:30 o'clock position about 16-in from top of pipe and had reduced the wall thickness to 0.500in, a reduction of about 26%. There were numerous other dents and gouges on the pipe adjacent to the failure. After the accident, OPS issued a HFO which ordered TETCO to reduce its pipeline MAOP by 30% and to conduct an ILI pig survey to identify dents, gouges, and other anomalies. As was our usual practice, OPS required TETCO to submit an ILI plan for our approval.

The TETCO ILI plan needed, with a extremely high degree of certainty, to be able to find similar gouging and denting similar to what existed in Edison before the rupture. The TETCO ILI plan, which was accepted by OPS, included an ultrasonic pig (NowSCO) to find dents in the pipe and a MFL pig (Tuboscope) to find gouge-like indications or corrosion in the pipe. Both tools were successfully run. The NowSCO tool did not indicate the presence of any dents on the top portion (7 o'clock to 5 o'clock) of the pipe. The Tuboscope MFL tool did not indicate any gouge-like signatures in the pipe or corrosion of any significance on the pipe. Data from both pigs were compared to determine which anomalies required exposure. After this evaluation, TETCO determined that 10 anomalies met its excavation requirements. All were dent indications located at the bottom of the pipe. While the data analysis did not identify any gouge-like indications or significant corrosion, TETCO did repair seven of the 10 dents because after they were exposed, light gouges, scratches, or light corrosion were found. All dents were inspected visually, by ultrasonic techniques, and by wet-fluorescent wet-magnetic-particle testing. No indications of cracks were found in the dents.

All the dents were caused by the pipe resting on rocks. No indications of mechanical damage were found on the pipeline. The Somastic coating originally used for the pipe coating was in excellent condition. Based on the ILI program, it became evident that the pipeline was not experiencing a corrosion problem. As a result of the successful ILI pigging program and evaluation, OPS allowed pressure restoration to its original maximum allowable operating pressure.

Transcontinental Gas Pipe Line Corp (TRANSCO) accident, Virginia - 1994

Accident of June 30, 1994

On June 30, 1994, an accident occurred on a TRANSCO 30-in gas transmission pipeline (Main Line A) in Culpeper, Virginia. The pipe involved was API 5LX, grade X-52, 0.325-in w.t., manufactured by Kaiser Steel, and installed in 1950. The failure occurred in a rural area. There were no deaths or injuries and the natural gas did not ignite. This accident occurred due to wall thinning caused by external corrosion. After the accident, TRANSCO proposed a remediation plan which included a ILI pig survey using a MFL tool (Tuboscope) for the 43-mile section of this pipeline. TRANSCO also proposed to hydrostatically test the pipeline before the ILI pig survey, and to keep
the line out of service until all pipeline repairs were completed. TRANSCO was able to do this because the line was looped in the area. After the data was evaluated, a total of 129 pipe excavations were performed resulting in 82 pipe cutouts (70 corrosion, 10 dents on the bottom of the pipe, and 2 taps were removed). After Transco completed all of the above testing and associated repairs, the line was returned to service with no pressure restriction.

This accident is included because it is an example of where, after a pipeline accident, the operator of its own initiative, offered to perform a remediation program that was very complete and extensive. In this case, OPS issued no Order and did not enter into a formal Agreement under our Title 49, CFR, Part 190 procedures. We simply accepted the remediation program sent to us in writing by a Vice President of TRANSCO.

Columbia Gas Transmission storage field accidents, West Virginia - 1993

On September 18, 1993, Columbia Gas Transmission experienced a 16-in pipeline drip failure at its storage facilities in Randolph County, West Virginia. On November 4, 1993, Columbia experienced another failure, this time on a 20-in pipeline drip at its storage facilities in Jackson County, West Virginia. Both failures were attributed to internal corrosion.

Based on the results of a joint investigation on these failures, by OPS and by the West Virginia Public Service Commission (WV PSC), OPS issued a HFO on December 16, 1993, for the Columbia Gas storage facilities in West Virginia. This Order required the immediate reduction in operating pressure on various West Virginia storage field pipelines. This Order is slightly different from those described in the previous examples, in that it did not specifically require the operator to develop and submit an ILI pig plan to OPS for approval. This example was included to represent another type of ILI pig utilized under an OPS Order.

The HFO required Columbia to develop a remedial action plan, subject to approval by OPS, to verify the integrity of the pipelines associated with Columbia’s storage facilities in West Virginia (note: OPS does not have regulations that cover the vertical pipelines going down into the storage field). Columbia’s approved remedial action plan included provisions to identify corrosive environments by the physical inspection of pipeline drips, by analysis of fluids obtained from pipeline drips, and by other appropriate testing and inspection methods. As a part of the approved remedial action plan, Columbia included the option to physically inspect pipelines utilizing an ILI pig.

Columbia utilized ILI tools to determine the existence or the extent of internal corrosion within its pipeline facilities associated with four separate West Virginia storage fields. Columbia utilized the Atlas Wireline Service’s Vertiline tool, which basically uses a low-resolution magnetic flux to identify wall loss. The tool is not self-propelled and is physically pulled through pipeline sections by mechanical cables. This tool has a maximum pull range between 4,000 to 5,000ft. The Vertiline tool was utilized on short pipeline segments where it was not practical or cost-effective to build launcher and receiver facilities required for the use of conventional ILI pigs.

Furthermore, there were many obstacles to deal with such as expanded barrel drips, tight bends, heavy-wall fittings, and heavy-wall transition sections that would not accommodate conventional ILI pigs. Columbia determined it was easier and more cost effective to cut into a line section and pull the Vertiline tool, rather than to modify the entire lines to accommodate conventional ILI pigs.

Other options considered were hydrostatic testing or complete replacement. Hydrostatic testing may have been more cost efficient at times; however, Columbia determined it would not have provided the detailed information produced by the Vertiline tool. The pipeline facilities where Columbia utilized the Vertiline tool represented a small fraction of the pipeline facilities that required integrity verification under the OPS Order. Columbia utilized ultrasonic testing, hydrostatic testing, bell-hole examination, and other techniques in areas not inspected by ILI tools. In some cases pipeline facilities were simply replaced.

Overall, Columbia utilized the Vertiline tool in over 17 miles of its pipelines associated with the West Virginia storage fields. Based on the results, Columbia replaced a total of over 1 mile of pipe that was found to have excessive internal corrosion, in various storage fields.
Texas Eastern Transmission Corp (TETCO) accident, Edison, New Jersey - 1994

On March 23, 1994, a failure occurred on TETCO's 36-in diameter gas transmission (Line #20) at the asphalt plant yard in Edison, New Jersey. The pipe involved is API 5L, Grade X-52, 0.675-in w.t., manufactured by Bethlehem Steel, and was installed in 1961. The rupture resulted in an explosion and fireball of up to 400 to 500 ft high. It caused minor injuries to over 100 people, and in-patient hospitalization of two people. It destroyed eight apartment buildings and approximately 1,500 apartment residents were evacuated, many of whom lost their homes. The incident received extensive media coverage. Based on the National Transportation Safety Board (NTSB) Pipeline Accident Report of 1994, the estimated property damage from the accident exceeded $25 million. According to NTSB, the probable cause of the pipe rupture was mechanical damage to the exterior surface of the pipe that reduced the wall thickness and likely created a crack in a gouge that grew over time. The NTSB determined that the gouge which failed was located at the 1:30 o'clock position about 16-in from top of pipe and had reduced the wall thickness to 0.500 in, a reduction of about 26%. There were numerous other dents and gouges on the pipe adjacent to the failure. After the accident, OPS issued a HFO which ordered TETCO to reduce its pipeline MAOP by 30% and to conduct an ILI pig survey to identify dents, gouges, and other anomalies. As was our usual practice, OPS required TETCO to submit an ILI plan for our approval.

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Transcontinental Gas Pipe Line Corp (TRANSCO) accident, Virginia - 1994

Accident of June 30, 1994

On June 30, 1994, an accident occurred on a TRANSCO 30-in gas transmission pipeline (Main Line A) in Culpeper, Virginia. The pipe involved was API 5LX, grade X-52, 0.325-in w.t., manufactured by Kaiser Steel, and installed in 1950. The failure occurred in a rural area. There were no deaths or injuries and the natural gas did not ignite. This accident occurred due to wall thinning caused by external corrosion. After the accident, TRANSCO proposed a remediation plan which included a ILI pig survey using a MFL tool (Tuboscope) for the 43-mile section of this pipeline. TRANSCO also proposed to hydrostatically test the pipeline before the ILI pig survey, and to keep
the line out of service until all pipeline repairs were completed. TRANSCO was able to do this because the line was looped in the area. After the data was evaluated, a total of 129 pipe excavations were performed resulting in 82 pipe cutouts (70 corrosion, 10 dents on the bottom of the pipe, and 2 taps were removed). After Transco completed all of the above testing and associated repairs, the line was returned to service with no pressure restriction.

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**Columbia Gas Transmission storage field accidents, West Virginia - 1993**

On September 18, 1993, Columbia Gas Transmission experienced a 16-in pipeline drip failure at its storage facilities in Randolph County, West Virginia. On November 4, 1993, Columbia experienced another failure, this time on a 20-in pipeline drip at its storage facilities in Jackson County, West Virginia. Both failures were attributed to internal corrosion.

Based on the results of this joint investigation on these failures, by OPS and by the West Virginia Public Service Commission (WV PSC), OPS issued a HFO on December 16, 1993, for the Columbia Gas storage facilities in West Virginia. This Order required the immediate reduction in operating pressure on various West Virginia storage field pipelines. This Order is slightly different from those described in the previous examples, in that it did not specifically require the operator to develop and submit an ILI pig plan to OPS for approval. This example was included to represent another type of ILI pig utilized under an OPS Order.

The HFO required Columbia to develop a remedial action plan, subject to approval by OPS, to verify the integrity of the pipelines associated with Columbia's storage facilities in West Virginia (note: OPS does not have regulations that cover the vertical pipelines going down into the storage field). Columbia's approved remedial action plan included provisions to identify corrosive environments by the physical inspection of pipeline drips, by analysis of fluids obtained from pipeline drips, and by other appropriate testing and inspection methods. As a part of the approved remedial action plan, Columbia included the option to physically inspect pipelines utilizing an ILI pig.

Columbia utilized ILI tools to determine the existence or the extent of internal corrosion within its pipeline facilities associated with four separate West Virginia storage fields. Columbia utilized the Atlas Wireline Service's Vertline tool, which basically uses a low-resolution magnetic flux to identify wall loss. The tool is not self-propelled and is physically pulled through pipeline sections by mechanical cables. This tool has a maximum pull range between 4,000 to 5,000ft. The Vertline tool was utilized on short pipeline segments where it was not practical or cost-effective to build launcher and receiver facilities required for the use of conventional ILI pigs.

Furthermore, there were many obstacles to deal with such as expanded barrel drips, tight bends, heavy-wall fittings, and heavy-wall transition sections that would not accommodate conventional ILI pigs. Columbia determined it was easier and more cost effective to cut into a line section and pull the Vertline tool, rather than modify the entire lines to accommodate conventional ILI pigs.

Other options considered were hydrostatic testing or complete replacement. Hydrostatic testing may have been more cost efficient at times; however, Columbia determined it would not have provided the detailed information produced by the Vertline tool. The pipeline facilities where Columbia utilized the Vertline tool represented a small fraction of the pipeline facilities that required integrity verification under the OPS Order. Columbia utilized ultrasonic testing, hydrostatic testing, bell-hole examination, and other techniques in areas not inspected by ILI tools. In some cases pipeline facilities were simply replaced.

Overall, Columbia utilized the Vertline tool in over 17 miles of its pipelines associated with the West Virginia storage fields. Based on the results, Columbia replaced a total of over 1 mile of pipe that was found to have excessive internal corrosion, in various storage fields.
OPS and the WV PSC concurred with Columbia’s replacement and non-replacement decisions mainly due to the excavation verification efforts (witnessed mostly by the WV PSC). The excavation verifications, which numbered over 50, validated the VertiLine tool’s wall-loss reports and subsequently-indications of internal corrosion. The tool inspection efforts, in conjunction with other Columbia storage field verification efforts, were essential factors in satisfying its remedial action plan required by the HFO.

This case represents the acceptance of a different type of ILI pig that is more applicable for identifying areas of internal corrosion (by measuring wall loss) in smaller-diameter pipe and in shorter sections of pipe. The use of the VertiLine tool was a factor in Columbia’s demonstration to OPS and the WV PSC, that its remedial action plan was successful. This eventually led to the removal of all pressure restrictions on pipeline facilities associated with the West Virginia storage fields, which in turn led to the closeout of the HFO on October 11, 1995.

LESSONS LEARNED

OPS recognizes there are certain limitations to ILI pigging surveys; for instance, ILI pigging tools do not have the capability to identify all types of anomalies in pipelines. There is no single ILI tool presently available today that can consistently and accurately find gouges caused by mechanical equipment in dents. However, despite this, OPS learned by utilizing a combination of tools, and using engineering judgement, ILI programs can be successfully run which can identify dents that are most likely to contain gouges. This can be accomplished by concentrating on dent anomalies on the top half of the pipe, identifying all sharp dents indications, and by using a combination of ILI pigs and comparing pig data.

The combination of pig tools are usually a MFL tool in conjunction with a ILI three-dimensional geometry-deformation tool. This is expensive, but the results of such programs have successfully rebuilt public and regulatory confidence in pipelines which have experienced failures where the pipeline had a gouge in a dent, and the gouge took years to fail (i.e. a time-dependent flaw).

OPS has also gained confidence in MFL tools in their ability to find corrosion and has accepted this technology in re-establishing integrity operations of a pipeline experiencing corrosion on the pipe body wall.

It also has become apparent that many gas-transmission and hazardous-liquid pipeline operators prefer ILI smart-pig programs over hydrostatic testing programs to re-establish the pipeline integrity, when an accident has been caused by a defect that can be detected by ILI tools. This has occurred because of improvements in ILI technology, the cost of hydrostatic testing, the associated cost of disposing of the hydrotest water, and the difficulty of securing all the necessary permits.

OPS has also learned that it needs to be selective in requiring ILI pig programs. OPS recognizes that many accidents occurring on both gas-transmission or hazardous-liquid pipelines do not require an ILI inspection program to demonstrate pipeline integrity. A good example is a third-party damage accident which fails immediately after mechanical damage occurs. Another example, where an ILI pig program would not be a OPS solution, would be for ILI technology to be used as the sole method utilized to find stress-corrosion cracking, although technology is developing which may make this possible in the future.

SUMMARY

OPS and pipeline operators have successfully utilized ILI technology to re-establish pipeline integrity after pipeline accidents. OPS will continue to require, on a case-by-case basis, ILI programs for specific pipelines to help establish integrity of a pipeline after an accident. OPS expects an-ILI program to play a major factor in Pipeline Operators’ risk-management programs. OPS will continue to encourage the use of ILI technology, and encourages research on improving ILI technology.
ACKNOWLEDGMENTS


LIST OF ABBREVIATIONS

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>CFR</td>
<td>Code of Federal Regulations</td>
</tr>
<tr>
<td>DSAW</td>
<td>double submerged arc welded</td>
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<tr>
<td>D/t</td>
<td>pipe diameter to wall thickness ratio</td>
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<tr>
<td>DOT</td>
<td>Department of Transportation</td>
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<tr>
<td>HFO</td>
<td>Hazardous Facility Order</td>
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<tr>
<td>ILI</td>
<td>in-line inspection</td>
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<tr>
<td>MAOP</td>
<td>maximum allowable operating pressure</td>
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<tr>
<td>MFG</td>
<td>manufacturer</td>
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<tr>
<td>MOP</td>
<td>maximum operating pressure</td>
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<tr>
<td>MFL</td>
<td>magnetic-flux leakage</td>
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<tr>
<td>NDE</td>
<td>non-destructive examination</td>
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<tr>
<td>NTSB</td>
<td>National Transportation Safety Board</td>
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<tr>
<td>OPS</td>
<td>Office of Pipeline Safety</td>
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<tr>
<td>RSFA</td>
<td>Research and Special Programs Administration</td>
</tr>
<tr>
<td>S/D</td>
<td>slope-deformation</td>
</tr>
<tr>
<td>SMYS</td>
<td>specified minimum yield strength</td>
</tr>
<tr>
<td>TETCO</td>
<td>Texas Eastern Transmission Corporation</td>
</tr>
<tr>
<td>TUBOSCOPE</td>
<td>Tuboscope Pipeline Services, Inc</td>
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<tr>
<td>VETCO</td>
<td>Vetco Pipeline Services, Inc</td>
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DEFINITIONS

*In-line-inspection pig* (ILI pig): An ILI tool is a pig which passes through a pipeline, usually propelled by the commodity (liquid and or gas) being transported, that can detect certain anomalies in the pipe wall. ILI pig has the capability to record location and relative severity of the anomaly through use of recording equipment (such as a magnetic tape recorder) carried on board the pig.

*Anomaly*: Pipeline defect such as a dent, gouge, crack, wall loss, etc.

*Dents*: As defined in ASME B31.8 or B31.4, 1992.

*Gouge*: As defined in ASME B31.8 or B31.4, 1992.

*Compliance Order*: As stated in the Pipeline Safety Regulations, Title 49, US CFR, Part 190.


*Consent Order*: As stated in the Pipeline Safety Regulations, Title 49, US CFR, Part 190.

*Agreement*: As stated in the Pipeline Safety Regulations, Title 49, US CFR, Part 190.
9.0 LIST OF ATTACHMENTS


2. Colonial - Consent Order (Agreement), CPF No. 14501-H.
Colonial - NTSB-Metallurgist Factual Report No. 93-66 (text only).
A. ACCIDENT

Place : Reston, Virginia
Date : March 28, 1993
Vehicle : 36 inch diameter pipeline
Operator : Colonial Pipeline
NTSB No. : DCA93-M-P007
Investigator : George Mocharko (ST-60)

B. COMPONENTS EXAMINED

Approximate 18-foot 4 inch long section of pipe containing a rupture and an approximate 11.2 foot long section containing a large dent in the bottom of the pipe.

C. DETAILS OF THE EXAMINATION

Background and Initial On-Site Examination

The subject pipe rupture was first examined on March 29, 1993 shortly after being exposed by excavation with a backhoe (see figure 1). At that time product (fuel oil) was still escaping from the rupture and hoses were inserted into the rupture opening to withdraw residual oil from the pipe to nearby tank trucks. The initial examination was hampered by flowing oil in the area. However, measurements showed that the rupture was mostly longitudinal extending approximately 42 inches and located near the top of the pipe. The maximum rupture opening was about 5 inches near the center of the rupture. A ball micrometer showed the thickness of the pipe wall directly adjacent to the mid section of the rupture (maximum opening) was 0.344 inches. Thickness measurements along the rupture further removed from the midpoint were significantly less, varying from 0.28 to 0.31 inches.

Information supplied by Colonial Pipeline representatives indicated the pipe's longitudinal direction was orientated north-south with product flowing in the northerly direction. For the purpose of this report, directions on the pipe will be indicated as if the pipe was orientated true north/south. Herein, clock positions will be referenced as if looking north along the center of the pipe with 12 o'clock being the top and 6 o'clock being the bottom of the pipe. Outward is away, and inward is toward, the pipe centerline.
Most of the oil was removed from the pipe section by the afternoon of the March 30th, and excavation continued from the area of the rupture to a point north about 400 feet. Figure 2 shows the pipe rupture in late afternoon of the 30th with the pipe still situated as excavated and the outside diameter partially cleaned with water and rags. Initial visual examinations of the rupture fracture surface disclosed crescent shaped fracture areas indicative of progressive cracking extending from multiple origin areas. The progressive cracking appeared to extend inward from the pipe O.D. surface to a maximum depth of 1/3 the pipe wall thickness over an approximate 5 1/4 inch longitudinal length. In order to assure that subsequent damage to fracture would not occur while removing a large pipe section, a specimen containing the suspected crack region was excised from the east fracture half of the rupture. This specimen, approximately 1 inch wide circumferentially by 8 inches longitudinally, was excised by drilling a line of holes and sawing between them with a reciprocating saw. On the morning of March 31, 1993 an 18 foot 4 inch section containing the remaining rupture and associated damage marks was saw cut removed from the pipe. This large pipe section along with the smaller previously removed specimen were transported to the NTSB Materials Laboratory in Washington D.C.

On April 1, 1993 the Materials Laboratory received an approximate 1 1/2 foot long torch cut removed section of the pipe that contained a large depression that was originally orientated along the bottom of the pipe between 27 and 30 feet north from the center of the pipe rupture.

The bulk of the longitudinal rupture was just west of the top of the pipe, about the 11:30 o'clock position, with the north and south ends of the rupture turning east toward the top of the pipe (see figure 2). The fracture half on the east was bulged outward and up in the form of a flap. The west fracture half was also bulged outward but to a much lesser degree than the east fracture half. The longitudinal weld seam for the pipe section containing the rupture was oriented at about 9:30 o'clock (see arrow "w", figure 1), well removed from the rupture. The nearest girth weld was about 12 feet south of the rupture. Most of the red colored protective pipe coating material was missing in the area of the rupture.

Oriented longitudinally along the pipe were what appeared to be deposit buildups resulting from electrolytic migration (because of cathodic protection) of soil elements to areas of exposed metal on the pipe outside diameter. In some areas, especially in the area of the rupture, no deposits were found and longitudinally aligned deformation markings could be seen in the pipe metal. One of these longitudinal mark areas is denoted by bracket "a" in figure 3, was about 8 foot 7 inches long (3 foot 2 inches north to 5 foot 5 inches south of the rupture center) and was in line with the longitudinal area of the rupture. Near the north end and superimposed over this longitudinal marking was an approximate 1/2 inch depression in the pipe as shown by arrow "d" in figures 3 and 4. To the south of, and slightly overlapping mark "a", was another separate longitudinal mark as indicated by bracket "b" in figure 3. Longitudinal mark "b" was circumferentially oriented just east (approximately 11:45 o'clock) of mark "a" and was about 5 foot 7 inches long (extending south between 4 foot 11 inches and 10 foot 6 inches from the rupture centerline). The smaller photo on the right in figure 3 shows a closer view of the area of overlap between marks "a" and "b".
Initial Laboratory-Examination

A photomontage of the pipe section as received in the laboratory and after further cleaning by water washing is shown in figure 5. The 1 inch by 8 inch fracture specimen previously removed in the field was from the area located by the smaller unmarked bracket in this figure. Longitudinal markings "a" and "b" and the approximate 1/2 inch deep dent "d" previous described are also indicated.

An approximate 2 inch circumferentially wide by 17 inch longitudinally long specimen was excised in the laboratory from the western fracture half in the area of the larger unmarked bracket shown in figure 5. This area contained the mating fracture surface displaying evidence of cracking on the fracture surface. The O.D. surface of the two fracture specimens is shown in figure 6 placed relative to each other by fracture matching. Figures 7 and 8 are sequentially higher magnification views of these specimens in the area of the progressive cracking on the fracture.

In the area of the rupture most of the surface finish was missing exposing the outside diameter metal surface of the pipe material. As indicated previously the eastern fracture half had bulged further outward than the western fracture half. The O.D. surface east and adjacent to the fracture contained numerous scratches and scrapes that were randomly oriented (see figures 7 and 8) and did not extend across the rupture to the western fracture half. Because these markings did not continue across the fracture they are believed to have occurred during or subsequent to the rupture.

Fractography

The mating fracture halves with the area of progressive cracking denoted by bracket "C" are shown in Figure 9. Stereo microscopic viewing of the fracture surfaces disclosed numerous crescent shaped regions in this area. A higher magnification view of the eastern fracture half is displayed in the top photograph of figure 10. The direction and extent of propagation of the two longest and deepest penetrating crescent crack areas are indicated by unmarked arrowheads in this photograph.

Initial examination of the eastern fracture specimen with the aid of a scanning electron microscope (SEM) indicated that the fracture had initiated in overstress and was followed by fatigue progressing to an overall maximum depth of 1/3 the pipe wall thickness. This initial SEM examination was hampered by residual deposits on the fracture surface that masked some of the fracture features. X-ray energy dispersive spectral analysis (EDS) of the deposits showed they were mainly iron oxides. To better examine the fracture features, an approximate 3/4 inch wide fracture specimen was removed from the eastern fracture in the area indicated by dimension "E1", figure 10. This specimen was electrolytically cleaned in Endox to remove most of the deposits. The lower views of figure 10 display sequentially higher magnification SEM photographs after Endox cleaning in the area of deepest fatigue penetration. Overstress fracture features were found from the O.D. surface to the beginning of the fatigue crack region (see area indicated between arrows "1" in the left lower photograph of figure 10). The fatigue region extended inward from the base of the O.D. overstress and a representative region is
shown within the area between arrows "2". One area within specimen E1 showed clear fatigue striations as seen in figures 11 and 12. Considerable effort was made to locate additional fatigue striations throughout the fatigue region but except for the area shown in figure 11, additional striations were not uncovered. All remaining fracture inward and away from the base of the fatigue regions was representative of an overstress separation stemming from the fatigue cracks.

Origin Area Damage to O. D.

Figure 13 shows composite views of the pipe O.D. adjacent to the fatigue region. Examination of this surface at the fracture interface disclosed a sawtooth shaped pattern. The sawtooth pattern (see brackets "m" and "n", figure 8) were on both the north and south sides of a central offset shear interface (area between brackets "m" and "n", figure 8).

Initial SEM examination of the O.D. disclosed considerable deposits still adhering to the surface. EDS of selected areas indicated a possible metal transfer (steel containing chromium and silicon) onto the O.D. surface. However, this initial chemical examination was hampered due to other numerous deposits in the area containing silicon, magnesium, aluminum and calcium oxides. To remove most of these deposits the surface was extensively electrolytically cleaned in Endox. Reexamination after this cleaning disclosed a 0.05 inch wide longitudinal band of what appeared to be transferred material onto the O.D. surface near the fracture plane. Figure 14, with higher magnification details in figure 15, show an example of the material transfer (outlined by arrowheads) as viewed on the specimen cleaned with Endox. EDS within the transfer consistently produced spectrums showing the material was steel (iron with some manganese) having small but significant peaks of chromium and silicon both of which had peak intensities about twice that of manganese. These spectra differed from those obtained from the pipe material which showed only iron with a small amount of manganese. The longitudinal extent of the material transfer appeared to be limited to the longitudinal area of the fatigue cracking (see arrows "C", figure 7). The circumferential width of the material transfer varied along the length, with the widest most concentrated amount being in area "n" (see figures 8 and 13). Bracket "T" in figure 13 denotes the approximate width of the transfer in area "n" (located between 0.05 and 0.10 inches west of the sawtooth fracture interface). Stereomicroscopic examination of the cleaned O.D. specimen also disclosed a discontinuous longitudinal crack running nearly parallel to and about 0.3 inches west of the fracture plane. This crack corresponded to but was shorter than the fatigue cracking area. Also observed on the O.D. surface near the area of metal transfer were much smaller longitudinal cracks, such as those shown by arrows "c1" in figure 14.

Metallurgical Sections

A longitudinal metallographic section was prepared in the central portion of the transfer at the location denoted by section "WSL" in figure 13. This section is, in part, displayed in figure 16. A thin white etching layer (arrowed "T", figure 16) of varying depth was noted throughout the section. Under this layer was a severely deformed microstructure indicative of plastic deformation of the pipe metal surface (see bracket "P", figure 16). The deformation flow lines clearly showed that the pipe surface was deformed in the southerly direction. EDS analysis of
the white layer showed it was steel with peak heights of chromium and silicon that were twice the intensity of the manganese peak (similar to that found in the previous analysis of the O.D.). The deformed layer below the white layer gave spectra consistent with the pipe material (iron and manganese only). Although the detector used in the EDS analysis can detect carbon, the percentages normally associated with steels (less than 0.5%) are not readily detected by this method.

Transverse metallurgical sections were taken in the areas denoted by sections "W1" and "EW" in figure 7. The microstructure, in general, was composed of ferrite and pearlite, as shown in Figure 17. Some stringer inclusions were found which appeared normal for the pipe steel specified (API - 5L). There was only a thin layer of partial decarburization at the inside and outside diameter surface (as indicated by higher concentrations of ferrite to pearlite then the matrix). However, this decarburization was slight and considered normal for the specified material.

Section "EW" containing mating areas from both fracture halves is displayed in figure 18. Selected areas of this section are also shown at higher magnification with a light nital etch applied to the specimens. Evidence of transferred metal on the O.D. surface was found in small areas of this section about 0.05 to 0.10 inch from the fracture plane (see lower photographs in figure 18 for details of transfer area). Other surface imperfections, one of which appeared to be a shear crack angled 45 degrees to the O.D. surface, were also noted in this section (see top photographs, figure 18). The shear crack was located about 0.27 inch west from the fracture plane, in a position corresponding to the discontinuous longitudinal crack in the fatigue area previously mentioned.

**Hardness**

Hardness measurements on section "W1" gave values between 187 and 192 Diamond Pyramid Hardness. Hardness conversion of these values using a Wilson Mechanical Instrument Chart indicated that the material had an approximate tensile strength of 90 KSI. A Colonial Pipeline representative indicated that the specified API-5L material was X52 having a required minimum tensile strength of 66 KSI and a minimum yield strength of 52 KSI. Although hardness does not directly convert to yield strength, the tensile strength indicated by hardness and the uniform, consistent microstructure were representative of a steel having a much higher yield stress than the required minimum.

Tukon hardness measurements (50 gram load) within the white layer of transferred material on the O.D. surface of section "W3L" gave values between 598 and 616 Knoop (HK). In the underlying plastic flowed pipe material, the same load measurements gave values between 434 and 654 HK (one measurement at the interface showed 740 HK). For comparison, the undeformed matrix material of the pipe yielded values of approximately 250 Knoop with a 50 gram load.
Pipe Damage Away From-Origin Area

Most of the pipe was still covered by its protective coating and/or contained deposits that the steel pipe surface masked from view. In order to view the steel surface in areas of suspected damage, the coating and deposits were selectively removed. This was done by first picking under the loose coating with a sharp object and flaking off areas of the brittle coating with particular care to not scratch the underlying steel surface. Vinegar was first used to help remove the deposits but this was found to be only mildly effective. Concentrated acetic and phosphoric acid removed more deposits and hydrochloric acid in concert with scraping was found to be most effective at removing almost all of the deposits. Acid cleaning was only performed in areas away from the rupture. As mentioned before, the areas adjacent to the rupture contained little or no protective coating or deposits and therefore, this area needed no acid cleaning. Acid cleaning was only performed in areas away from the rupture.

Figures 19 and 20 show selected areas of the pipe O.D. surface after removing the coating and deposits. Locations of these selected areas are shown by arrows "d", "h", "j", "k", "u" and "v" in figure 5. Areas "d" and "u" were inward dents in the pipe that measured a maximum of approximately 1/2 inch and 1/4 inch deep, respectively, from a longitudinal flat on the O.D. Figure 21 shows the pipe dent area on the bottom of the pipe located about 25 feet north of the rupture. Measurement of this dent showed it was approximately 3/4 inch deep at its maximum point.

Before extensive removal of the deposits began, a small specimen approximately 4 inch longitudinally by 2 inch circumferentially that incorporating a portion of the "b" longitudinal deposit mark was saw cut removed from the pipe. The bracket arrowed "b1" in figure 5 denotes the location of this specimen. Examination of the specimen surface, after electrolytic cleaning in Endox, disclosed shallow mechanical surface damage with characteristics similar to the that shown in area "k" in figure 19. Microscopic viewing of the damage disclosed what appeared to be small metal folds in the deeper areas of the mechanical damage that were indicative of an object sliding longitudinally against the pipe O.D. in the southerly direction.
Colonial - Consent Order (Agreement), CPF No. 14501-H.
Hydrostatic testing will begin in the third quarter of 1995, for the Louisa, Virginia to Remington, Virginia portion and in the second quarter of 1996 for the Remington, Virginia, to Dorsey Junction, Maryland portion. If hydrostatic testing of the line becomes necessary because of an unsuccessful elastic wave pig run, such testing would begin as soon as reasonably practicable for the Louisa, Virginia, to Remington, Virginia portion, following such a determination.

Colonial will perform a hydrostatic test of the pipeline at a pressure between 100% of the segment's specified minimum yield strength (SMYS) at its lowest elevation, and 85% SMYS at its highest elevation.

10. With respect to Colonial's 32-inch pipeline:

a. Colonial agrees to run a Vetco magnetic flux leakage tool on its Greensboro, North Carolina, to Dorsey Junction, Maryland, pipeline segment. This pig will be run by the end of the second quarter 1997. The slope/deformation tool from Greensboro, North Carolina, to Dorsey Junction, Maryland, was run during April 1995.

b. Under the Agreed Plan for Testing Pipeline Facilities in CPP 10504A, Colonial is restricted from increasing the MOP of this line above 445 psig at the Louisa pump station, and from increasing the set pressure of the relief valves in Chantilly, Virginia above 330 psig. In deciding whether to permit an increase in operating pressure under that Order, the Director will consider whether successful inspections using internal instrumented inspection devices in accordance with Paragraph 9(a) of this Agreement and repairs or replacement in accordance with Paragraph 11 of this Agreement have been successfully completed.
11. With respect to those actions specified in paragraphs 8
and 10 above, Colonial agrees to expose all dents that
have a depth of at least 6% of the nominal diameter of the
pipe and all dents on welds. In addition, Colonial agrees
to expose all anomalies on the top half of the pipe and
all buckles, regardless of their depth. Furthermore,
Colonial agrees to develop a risk assessment methodology
to determine the priority for repairing those sharp dents
over 2% of the pipeline's nominal diameter. The risk
assessment methodology is subject to the approval of the
Director. Colonial will perform a wet magnetic particle
inspection on all exposed anomalies found with any
scratch, gouge or groove indication from the running of
these tools. Colonial agrees to submit risk assessment
methodology as soon as practicable, but no later than
September 15, 1995.

12. Colonial agrees to provide OPS with analyses obtained
following successful smart pig runs within 10 days after
completion of the respective analyses.

13. OPS agrees to withdraw the Notice with respect to
Colonial's 22-inch and 6-inch pipelines.

14. Colonial agrees to permit OPS, state and local government
representatives to observe (at their expense) any of the
testing provided for in Paragraphs 8, 9 and 10 of this
Agreement. Colonial agrees to provide OPS forty-eight
(48) hours advance notice prior to beginning a test.

15. Any decision made by the Director may be appealed to the
Associate Administrator for Pipeline Safety.

16. This Agreement constitutes a settlement of all matters
raised in the Notice on facts known to OPS at the time of
this Agreement.

17. The Director may grant an extension of time, upon receipt
of a written request stating reasons therefor, for
completion of any of the actions required herein.

18. The effective date of this Agreement shall be the date
upon which a consent order incorporating the terms of this
Agreement is issued.
b. Colonial is restricted by the Hazardous Facility Order issued to it on March 30, 1993, CPF No. 13503-M, from increasing the maximum operating pressure (MOP) of this line to a maximum pressure greater than 80% of certain segments of MOP prior to the accident. In deciding whether to permit an increase in operating pressure under that Order, the Director will consider whether successful inspections using internal instrumented inspection devices in accordance with Paragraph 8(a) of this Agreement and repairs or replacement in accordance with Paragraph 11 of this Agreement have been successfully completed.

c. Colonial agrees to reinspect the Chantilly, Virginia to Dorsey Junction, Maryland segment of this line by October 31, 2000, using both a slope/deformation pig and a magnetic flux leakage tool. Within 15 days following completion of each reinspection report, Colonial agrees to ensure that OPS will receive the results of the analyzed data.

9. With respect to Colonial's 32-inch pipeline, Colonial agrees to conduct one of the following two tests:

a. Internal inspection using the British Gas elastic wave pig between Louisa, Virginia and Remington, Virginia and between Remington, Virginia and Dorsey Junction, Maryland. If this option is selected, Colonial further agrees that:


(ii) Colonial will submit a plan for conducting the internal instrumented inspection of the Remington, Virginia to Dorsey Junction, Maryland segment for approval from the Director. With respect to inspections on the Louisa to Remington, Virginia segment, Colonial agrees to submit a plan for the Director's approval that addresses the corrective action elements in 9(a)(iii). Colonial agrees to submit the plans by August 18, 1995.
(iii) The plans will:

(A) Describe the minimum crack defects that will be identified by the pig, in terms of length and width of defects. Cracks adjacent to the longitudinal weld that are at least as short as 2¼-inch in length, and at least as deep as 25% of the nominal wall thickness of the pipe must be identifiable.

(B) Include non-destructive techniques to evaluate anomalies, destructive testing evaluation criteria, if any is needed, and other techniques to demonstrate the effectiveness of the pig run.

(C) Include acceptance criteria that use engineering calculations to determine whether cracks or crack-like features remaining in the line will grow by fatigue due to the normal operating pressure fluctuations during service.

(iv) Taking the crack growth data described in paragraph 9(a)(iii)(C) into account, Colonial agrees to prepare an analysis to determine how long the pipeline could safely operate with those remaining cracks before another internal inspection, using a smart pig that could detect longitudinal seam defects, is needed. Colonial agrees to submit this analysis to the Director within 120 days after completion of the elastic wave pig run.

(v) The success of the pig run is subject to concurrence by the Director. In order to provide the Director adequate assurance that the pig data produced on Colonial’s line accurately identifies the anomalies described in Paragraph 9(a)(iii), Colonial agrees to submit to the Director, for approval, a validation procedure within the 120 day period following completion of the elastic wave pig run.

b. Hydrostatically test the pipeline between Louisa, Virginia, and Dorsey Junction, Maryland. If this option is selected, Colonial further agrees that:
AGREEMENT BETWEEN THE OFFICE OF PIPELINE SAFETY
AND COLONIAL PIPELINE COMPANY IN

CPP No. 14501-H

WHEREAS, on May 16, 1994, the Office of Pipeline Safety (OPS),
Research and Special Programs Administration (RSFA), issued to
Colonial Pipeline Company (Colonial), as the operator of
pipelines subject to the pipeline safety laws at 49 U.S.C.
§ 60101 et seq., a Notice of Proposed Hazardous Facility Order
(Notice) pursuant to § 60112(b);

WHEREAS, the Notice applied to the following Colonial pipelines
operating in Virginia, Maryland and North Carolina:

1. 36-inch line operating between Greensboro, North
   Carolina and Dorsey Junction, Maryland (36-inch
   line);
2. 32-inch line operating between Greensboro, North
   Carolina and Dorsey Junction, Maryland (32-inch
   line);
3. 22-inch line operating between Chantilly, Virginia
   and the Fairfax Tank Farm (22-inch line); and
4. 6-inch line operating between the Fairfax Tank Farm
   and Dulles Airport (6-inch line).

WHEREAS, the Notice proposed requiring Colonial to perform
corrective action on its 36-inch, 32-inch, 22-inch and 6-inch
pipelines as described in the Notice;

WHEREAS, following issuance of the Notice, OPS learned that
Colonial’s 22-inch pipeline was successfully hydrostatically
tested in 1990, and is scheduled for an internal instrumented
inspection in 1997, and that Colonial’s 6-inch line was
successfully hydrostatically tested in 1993, and inspected by a
magnetic flux tool in August, 1994;

WHEREAS, Colonial has contested the basis for the Notice’s
issuance, and requested a hearing to challenge the Notice; and

WHEREAS, Colonial agrees voluntarily to undertake corrective
action proposed in the Notice with respect to the 36-inch and
32-inch lines, and to internally inspect its 22-inch and 6-inch
lines; OPS finds it appropriate to enter into this Agreement.

Therefore, Colonial and OPS agree as follows:

1. Colonial, as owner and operator of the hazardous liquid
   facilities to which the Notice applies, is subject to
   the jurisdiction of 49 U.S.C. § 60101 et seq. and
   administrative orders issued pursuant thereto.
2. Colonial agrees to the issuance of an administrative order (consent order) incorporating the terms of this Agreement and waives any further procedural requirements, other than notice itself, with respect to its issuance and all rights to seek judicial review or otherwise contest its validity.

3. OPS agrees not to make a determination of hazardous facility order against Colonial based on the May 16, 1994 Notice in this case. However, nothing in this Agreement bars RSPA from taking action based upon new evidence to address any hazardous situation which may arise with respect to Colonial's facilities.

4. As of the date of this Agreement, OPS investigation of both accidents has not revealed any alleged violations of the pipeline safety laws. Nothing in this Agreement bars RSPA from taking action based upon further analysis or new evidence to address any potential violations of the pipeline safety laws or the regulations promulgated thereunder.

5. Any actions required by the terms of this agreement shall be in addition to other duties imposed by 49 U.S.C. Chap. 601, and the regulations promulgated thereunder. Compliance with the terms of this Agreement shall not excuse any failure to comply with the other requirements under 49 U.S.C. Chap. 601 and the regulations promulgated thereunder. The actions required by this Agreement are in addition to duties imposed by the pipeline safety laws and the regulations promulgated thereunder.

6. Colonial has voluntarily decided to enter into this agreement with OPS.

7. The terms of this Agreement may be construed by reference to the Notice and to the December 6, 1994 letter from Colonial to William Gute, Eastern Region Director, OPS (Director). In case of conflict, the terms of this Agreement shall control.

8. With respect to Colonial's 36-inch pipeline:

   a. Colonial ran a slope/deformation pig between Greensboro, North Carolina and Dorsey Junction, Maryland in December 1994 and a magnetic flux leakage tool in March 1995. The manufacturer of the pig, Vetco Inc. (Vetco), is currently analyzing this data. Colonial agrees to ensure that OPS will receive the results of the analyzed data by August 18, 1995.
IT IS HEREBY AGREED:

OFFICE OF PIPELINE SAFETY

[Signature]
Richard B. Felder
Associate Administrator for Pipeline Safety

COLONIAL PIPELINE COMPANY

[Signature]
Donald Brinkley
President, Colonial Pipeline Company

Date: 8/14/75

Date: 8/19/95