U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

8701 S. Gessner, Suite 630
Houston TX 77074

NOTICE OF PROBABLE VIOLATION
and
PROPOSED CIVIL PENALTY

ELECTRONIC MAIL - RETURN RECEIPT REQUESTED

July 22, 2022

Eric Amundsen
Senior Vice President, Operations
Florida Gas Transmission Company
1300 Main Street
Houston, Texas 77002

CPF 4-2022-032-NOPV

Dear Mr. Amundsen:

From September 13, 2020 through September 23, 2021, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code (U.S.C.), inspected Florida Gas Transmission Company's (FGT) Sanford Lateral Pipeline following an incident that occurred at 00:52 a.m. EDT on September 10, 2020, in a marshy powerline corridor in Sanford, Florida.

FGT's 12-inch Sanford Lateral ruptured, and the escaping gas ignited while operating at about 688 pounds per square inch gauge (psig). FGT's Control Center detected a low-pressure alarm and field operations personnel confirmed the failure was on the Sanford Lateral. By 2:09 a.m. about 32 homes and 93 businesses were evacuated until after the fire was extinguished. There were no reported injuries or fatalities. The estimated release was 22 million cubic feet of natural gas. PHMSA's Accident Investigation Division and the Southwest Region initiated an investigation into the incident.

PHMSA issued a corrective action order (CAO) to FGT (CPF 4-2020-008-CAO) that required a shutdown of the isolated segment, a pressure restriction restart plan, a return-to-service plan, a records verification, a review of inline inspection (ILI) results, a metallurgical laboratory examination, a root cause failure analysis, and a remedial work plan. With PHMSA's Southwest Region approval, FGT repaired the pipeline and returned it to service on December 7, 2020.

As a result of the inspection, it is alleged that FGT has committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (C.F.R.). The items inspected and the probable violations are:

1. **§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.**

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

(1) …

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	**Pressure date**	**Test date**
(i) Onshore regulated gathering pipeline (Type A or Type B under § 192.9(d)) that first became subject to this part (other than § 192.612) after April 13, 2006	**March 15, 2006, or date pipeline becomes subject to this part, whichever is later**	**5 years preceding applicable date in second column.**
(ii) Onshore regulated gathering pipeline (Type C under § 192.9(d)) that first became subject to this part (other than § 192.612) on or after May 16, 2022	**May 16, 2023, *or date pipeline becomes subject to this part, whichever is later***	**5 years preceding applicable date in second column.**
(iii) Onshore transmission pipeline that was a gathering pipeline not subject to this part before March 15, 2006	**March 15, 2006, or date pipeline becomes subject to this part, whichever is later**	**5 years preceding applicable date in second column.**
(iv) Offshore gathering pipelines	**July 1, 1976**	**July 1, 1971.**
(v) All other pipelines	**July 1, 1970**	**July 1, 1965.**

FGT failed to establish a Maximum Allowable Operating Pressure (MAOP) for its Sanford Lateral in accordance with § 192.619(a)(3). Specifically, FGT failed to provide records to substantiate its MAOP determination.

FGT failed to provide records to subsantiate the highest actual operating pressure that the segment was subjected to during the five years prior to MAOP establishment. FGT submitted an MAOP Authorization Sheet, dated November 1, 1989, that had been completed by personnel of the prior operator attesting to the MAOP of Sanford Lateral. However, FGT failed to submit any operating pressure records. In accordance with the requirements of the CAO, on November 2, 2020, FGT conducted a hydrostatic test to establish the MAOP in accordance with § 192.619(2).

Therefore, FGT failed to establish an MAOP for its Sanford Lateral in accordance with § 192.619(a)(3).

2. § 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

FGT failed to identify and evaluate all potential threats to each covered pipeline segment in its natural gas pipeline systems in accordance with § 192.917(a)(1). Specifically, since FGT failed to inspect the covered segments of the Sanford Lateral for Stress Corrosion Cracking (SCC), it did not include the Sanford Lateral as part of its SCC program. Nor did FGT consistently evaluate for SCC when the line was exposed.

The Sanford Lateral is a 15.9-mile natural gas pipeline, with many covered segments, that originates at the Sanford take-off pig launcher and terminates at the Debary regulator pig receiver. The pipeline is composed primarily of API 5L Grade X42, 12.75-inch outside diameter, .219-inch wall thickness pipe manufactured by Youngstown Sheet & Tube in 1959. The pipe's longitudinal seam was produced by using a Low-Frequency Electric Resistance Welded (LF ERW) manufacturing process. The coating was originally Polyken 960, a cold, field-applied tape coating that is spiral-wrapped. Pipe of this vintage, manufacturing type, and coating type has previously shown high susceptibility to SCC.

FGT has over 30 pipelines, including 13 laterals in its SCC program within the state of Florida. Many are of similar vintage, manufacturing type, and coating type as the Sanford Lateral. Despite finding SCC on lines with similar characteristics in the immediate vicinity, including FLMEA-17, the line that supplies gas to the origination point, Sanford Lateral was not part of the FGT SCC program. Instead, FGT evaluated for SCC on the Sanford Lateral whenever pipe was "exposed or found to be exposed."[1]

[1] SOP D.35 Buried Pipe Inspections, at 1.

Furthermore, in accordance with its Life Cycle Management of Surface Breaking Linear Indications Best Practice, once FGT determines that covered segments of a pipeline are susceptible to SCC, it adds the entire pipeline (both covered and non-covered segments) to the SCC program. Therefore, had FGT evaluated for SCC on the covered segments of Sanford Lateral, it would have been required to add the entire line to the SCC program.

During the inspection, PHMSA examined records showing that some exposed pipe on Sanford Lateral was examined for SCC using wet magnetic particles, a type of Non-Destructive Examination. In other instances, no wet magnetic particle examination was done for SCC on the exposed pipe.

In 2018, 24,102 feet of the Sanford Lateral was re-routed to accommodate an adjacent road (Wekiva Parkway) expansion. FGT excavated, exposed, sand-blasted, and cut into the existing pipeline in four different locations. Portions of the existing line were removed to allow the newer pipe to be connected to the original pipe at four tie-in welds. The remaining portions of the existing line that were no longer being used were abandoned in place. FGT was unable to produce any records demonstrating that these locations were well-bonded over the entire pipe circumference or that it conducted SCC examinations using wet magnetic particles on the exposed pipe at any of the four locations.[2]

FGT's failure to inspect the covered segments of the Sanford Lateral for SCC and its failure to consistently evaluate for SCC when the line was exposed were causal factors in the incident.

Therefore, FGT failed to identify and evaluate all potential threats to each covered pipeline segment in its natural gas pipeline systems in accordance with § 192.917(a)(1).

3. § 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) …

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (ibr, *see* § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.[3]

[2] Exhibit B Consolidated Evidence, SOP D.35 Buried Pipe Inspections (Effective Date: 05/01/18), Section 7.1.

[3] Section 192.937(c) and (d) were amended on October 1, 2019, after FGT conducted its 2014 and 2019 ILIs.

FGT failed to follow ASME/ANSI B31.8S, section 6.2 in selecting the appropriate internal inspection tools for each covered segment. Specifically, FGT used an ILI tool for its ILI runs in 2014 and 2019 that was designed primarily to evaluate circumferential defects rather than axial defects on the Sanford Lateral.

Sanford Lateral is a 15.9-mile natural gas pipeline that originates at Sanford take-off pig launcher and terminates at Debary regulator pig receiver. The pipeline is composed primarily of API 5L Grade X42, 12.75-inch outside diameter, .219-inch wall thickness pipe manufactured by Youngstown Sheet & Tube in 1959. The pipe's longitudinal seam was produced using a LF ERW manufacturing process.

Pre-1970 LF ERW pipe has been found in numerous studies to have a higher risk of longitudinal seam failure. Because of the higher risks associated with pre-1970 LF ERW, an operator must select an assessment method most likely to detect the threats. *ASME/ANSI B31.8S* (incorporated by reference) *Section 6.2.1(e)* states that the Transverse Flux Tool (commonly referred to as Magnetic Flux Leakage Circumferential or MFL-C) "is more sensitive to axially aligned metal-loss defects."

FGT used a Magnetic Flux Leakage Axial in calendar years 2014 and 2019 for the Sanford Lateral despite the elevated risk of longitudinal seam failure, a type of axial defect.

Therefore, FGT failed to follow ASME/ANSI B31.8S, section 6.2 in selecting the appropriate internal inspection tools for each covered segment in accordance with § 192.937(c)(1).

<u>Proposed Civil Penalty</u>
Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed $239,142 per violation per day the violation persists, up to a maximum of $2,391,412 for a related series of violations. For violation occurring on or after May 3, 2021 and before March 21, 2022, the maximum penalty may not exceed $225,134 per violation per day the violation persists, up to a maximum of $2,251,334 for a related series of violations. For violation occurring on or after January 11, 2021 and before May 3, 2021, the maximum penalty may not exceed $222,504 per violation per day the violation persists, up to a maximum of $2,225,034 for a related series of violations. For violation occurring on or after July 31, 2019 and before January 11, 2021, the maximum penalty may not exceed $218,647 per violation per day the violation persists, up to a maximum of $2,186,465 for a related series of violations. For violation occurring on or after November 27, 2018 and before July 31, 2019, the maximum penalty may not exceed $213,268 per violation per day, with a maximum penalty not to exceed $2,132,679. For violation occurring on or after November 2, 2015 and before November 27, 2018, the maximum penalty may not exceed $209,002 per violation per day, with a maximum penalty not to exceed $2,090,022.

We have reviewed the circumstances and supporting documentation involved for the above probable violations and recommend that you be preliminarily assessed a civil penalty of **$834,400** as follows:

Item number	PENALTY
1	$ 46,600
2	$362,800
3	$425,000

Response to this Notice
Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Enforcement Proceedings*. Please refer to this document and note the response options. All material submitted in response to this enforcement action may be made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document, you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

Following the receipt of this Notice, you have 30 days to submit written comments or request a hearing under 49 C.F.R. § 190.211. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order. If you are responding to this Notice, we propose that you submit your correspondence to my office within 30 days from the receipt of this Notice. This period may be extended by written request for good cause.

In your correspondence on this matter, please refer to **CPF 4-2022-032-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

MARY LOUISE MCDANIEL

Digitally signed by MARY LOUISE MCDANIEL
Date: 2022.07.22 07:47:31 -05'00'

Mary L. McDaniel, P.E.
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Enforcement Proceedings*