Response of Texas Gas Transmission, LLC
To Notice of Probable Violation, Proposed Civil Penalty,
and Proposed Compliance Order

Texas Gas Transmission, LLC (Texas Gas) submits its Response to the Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice) issued on January 21, 2022, following an inspection performed by the Office of Pipeline Safety (OPS) in 2020 and 2021. On February 2, 2022, the Pipeline and Hazardous Materials Safety Administration (PHMSA) approved by email an extension of time until April 21, 2022, to respond to the Notice. This response is timely.

Texas Gas is committed to public safety and operating its pipeline facilities in accordance with the PHMSA’s regulations. Texas Gas takes PHMSA’s allegations of violation seriously, however, certain allegations in the Notice are legally and factually unsupported and must be withdrawn. As discussed below, Texas Gas contests Item 5, Item 6, Item 8, Item 11, and Item 13.

Concurrently with this written response, Texas Gas is submitting a Request for a Hearing, a Preliminary Statement of Issues and Request for Settlement Meeting pursuant to 49 C.F.R. § 190.208(a)(4) and § 190.211 and as permitted under 49 U.S.C. § 60117(b)(1). Texas Gas is requesting the settlement meeting to discuss resolving these allegations and also is requesting that the presiding official delay scheduling a hearing to allow the parties sufficient time to convene a meeting to resolve issues through a settlement.

Texas Gas does not contest Item 1, Item 2, Item 3, Item 4, Item 7, Item 9, Item 10 and Item 12.

I. Executive Summary

Item 5 § 192.605(a) Procedural manual for operations, maintenance, and emergencies. Texas Gas contests the allegation that it failed to follow its procedure for inspecting gas detection units at the Dillsboro Compressor Station because the alleged facts regarding the status of the gas

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1 Texas Gas is a wholly-owned operating subsidiary of Boardwalk Pipelines, LP (Boardwalk).
detector units are incorrect. When compressor engines #1, #2, #3, #9, and #10 were dismantled for repairs and upgrades in 2017, the gas detector units for these engines were permanently removed from service. Contrary to statements in the Notice, these gas detector units were not “returned to service” and were not “re-inspected” in 2018. When the repaired and upgraded compressor engines were restored to service in late 2017 and early 2018, Texas Gas installed new gas detector units for each engine. Texas Gas did not miss the summer 2017 inspection cycle for these units and did not fail to comply with its procedure. The alleged violation and proposed civil penalty must be withdrawn.

**Item 6 § 192.605(b)(8) Procedural manual for operations, maintenance and emergencies.**
Texas Gas contests Item 6 because the information relied on by OPS does not support the allegation. The Notice relies on Texas Gas’s Form 1000-20 to support the allegation that Texas Gas did not “document any the assessment of work performed as part of the operations and maintenance procedures.” Form 1000-20 is not the form Texas Gas uses to document with § 192.605(a)(8). Texas Gas uses Form 1000-10 to document changes made to procedures under § 192.605(a)(8). The proposed compliance order requiring Texas Gas to draft procedures must be withdrawn because the Notice does not allege that Texas Gas lacks a procedure or that Texas Gas’s existing procedure is inadequate. OPS has not met its burden of proving that the proposed remedy is appropriate.

**Item 8 § 192.619(a)(1) Maximum allowable operating pressure: Steel or plastic pipelines.**
Texas Gas contests Item 8 because the Notice fails to explain how Texas Gas allegedly violates § 192.619(a)(1)(ii). The Notice fails to comply with § 190.207(b)(1) which requires that a notice of probable violation include statement of evidence upon which the allegations are based. If not withdrawn for failing to comply with § 190.207(b)(1), then Item 8 must be withdrawn because the Notice incorrectly suggests that a maximum allowable operating pressure (MAOP) established under § 192.555(d)(2) is automatically nullified by a class location change. This suggestion is not supported by any PHMSA decision, interpretation or guidance and is contrary to § 192.611. The assertion that Texas Gas is required to confirm or revise MAOP under § 192.611 is incorrect and inconsistent with the plain language of that regulation. The proposed compliance order and proposed civil penalty also must be withdrawn.

**Item 11 § 192.706(a) Transmission lines: Leakage surveys.**
Texas Gas contests this alleged violation because OPS has not satisfied its burden of proving that Texas Gas conducted leakage surveys using improper leak detection equipment on transmission pipelines in Class 3 locations. First, OPS has not demonstrated that the leak detection equipment listed in the Notice is improper or inappropriate for detecting leaks in a pipeline right of way. The Notice does not identify any undetected leak or leak incident and OPS provides no technical analysis explaining why the leak detectors used by Texas Gas are not designed for detecting leaks that come from pipe located below ground. OPS also does not explain the concentration levels a leak detector must be capable of measuring in a pipeline right of way or why the leak detectors identified in the Notice cannot detect gas at those concentrations. Second, information contained in the Violation Report does not demonstrate that the leakage surveys listed in the Violation Report were performed using the equipment alleged to be improper or that these leakage surveys were performed in Class 3
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locations. The allegation, proposed compliance order and proposed civil penalty must be withdrawn.

Item 13: § 192.947(d) What records must an operator keep? Texas Gas contests the alleged violation in Item 13. Each preventative and mitigative (P&M) measure selected and implemented by Texas Gas in the ten high consequence areas (HCA) identified in the Notice is supported by a Risk Analysis, a completed Preventative and Mitigative Measures form (P&M Form), the Boardwalk Integrity Management Plan, and ASME/ANSI B31.8S. Each measure is plainly tailored to mitigate risks associated with the threats identified in each HCA. The Notice does not identify either a pipeline or public risk resulting from the alleged lack of documentation or any incremental safety benefit created by having any additional documentation. The proposed civil penalty also must be withdrawn as excessive, unwarranted, and disproportionate to the alleged violation.

II. Response of Texas Gas

A. PHMSA Bears the Burden of Proving the Allegations in the Notice.

PHMSA has the burden of proving that Texas Gas has violated the pipeline safety regulations. PHMSA has the “‘burden of production,’ i.e., . . . the obligation to come forward with the evidence at different points in the proceeding,” and the “‘burden of persuasion,’ i.e., which party loses if the evidence is closely balanced.” PHMSA “bears the burden of proof as to all

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4 Schaeffer v. Weast, 546 U.S. 49, 56 (2005) (quoting Dir., Office of Workers’ Comp. Programs, Dep’t of Labor v. Greenwich Collieries, 512 U.S. 267, 272 (1994)); see also In re Butte Pipeline Co., Final Order, CPF No. 5-2007-5008, 2009 WL 3190794, *1 (Aug. 17, 2009) (“PHMSA carries the burden of proving the allegations set forth in the Notice, meaning that a violation may be found only if the evidence supporting the allegation outweighs the evidence and reasoning presented by Respondent in its defense.”) (internal citation omitted).
elements of the proposed violation.” To meet its burden of production, PHMSA must present sufficient evidence to sustain an allegation of violation. Where PHMSA does not produce such evidence, the allegation of violation must be withdrawn. If the cited regulatory provision does not relate to the alleged problem, the alleged violation must be withdrawn.

To meet its burden of persuasion, PHMSA “must prove, by a preponderance of the evidence, that the facts necessary to sustain a probable violation actually occurred.” This burden is carried “only if the evidence supporting the allegation outweighs the evidence and reasoning presented by Respondent in its defense.” A respondent will prevail under this standard not by conclusively proving compliance, but where its rebuttal evidence is more persuasive than the evidence provided by PHMSA. If “the evidence is closely balanced,” PHMSA has not met its burden of persuasion and the allegation of violation must be withdrawn.

B. Texas Gas Did Not Fail to Comply With Section 9040 of Its O&M Manual.

Item 5 of the Notice asserts that Texas Gas did not follow Section 9040 of its operation and maintenance (O&M) procedures for inspecting the gas detectors at the Dillsboro Compressor Station in alleged violation of § 192.605(a) which requires that an operator “prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response.” Section 9040 of Texas Gas’s O&M Manual describes

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6 See, e.g., Tennessee Gas Pipeline, 2019 WL 7943664 at *5 (withdrawing alleged violation because OPS did not meet its burden of proving a violation); ExxonMobil, 2019 WL 3734516 at **4, 5 (ordering withdrawal of allegations where OPS failed to prove that Respondent engaged in conduct that would constitute a violation); In re Plains Pipeline, L.P., Final Order, CPF No. 4-2009-5009, 2011 WL 1919520, **4, 5 (Mar. 15, 2011) (ordering withdrawal of allegation when limited evidence in the record was not conclusive); In re EQT Corp., Final Order, CPF No. 1-2006-1006, 2010 WL 2228558, **6, 7 (May 13, 2010) (finding that OPS did not present evidence or analysis proving that Respondent’s actions was inadequate under the regulation); In re Bridger Pipeline Co., Decision on Reconsideration, CPF No. 5-2007-5003, 2009 WL 2336991, **5, 6 (June 16, 2009) (finding evidence introduced by PHMSA insufficient to establish a violation).
7 In re Rocky Mountain Pipeline Sys., Final Order, CPF No. 5-2004-5001, 2006 WL 4488857, **6, 8 (Dec. 11, 2006) (withdrawing alleged violations where the cited regulations did not relate to alleged violation).
9 In re Butte Pipeline, 2009 WL 3190794 at *1 (internal citation omitted).
10 See ANR Pipeline, 2012 WL 7177134 at *3. In ANR Pipeline, PHMSA found that ANR’s “plausible” explanation regarding the discovery of a reportable condition on its pipeline was sufficient to warrant withdrawal of the allegation of violation because the “Violation Report contain[ed] no evidence which would rebut ANR’s argument.” Id. See also In re City of Richmond, VA, Final Order, CPF No. 1-2004-0006, 2006 WL 3825337, *4 (Jan. 12, 2006) (stating that the Respondent does not have the burden of proving compliance, rather OPS has the burden of proving the violation).
12 49 C.F.R. § 192.605(a); Notice at 4; Pipeline Safety Violation Report, CPF No. 3-2022-019-NOPV at 17 (2022) (Violation Report).
the procedure for implementing § 192.736 which requires that “[e]ach gas detection and alarm system” required in a compressor station building “be maintained to function properly. The maintenance must include performance tests.”

Consistent with this regulation, Section 9040 requires that a “functional test” of each compressor station gas detection system be performed annually, not to exceed 15 months.

The Notice alleges the following:

Texas Gas did not have any 2017 inspection records for the gas detectors associated with engines 1, 2, 3, 9, and 10 at its Dillsboro compressor station. The gas detectors for these engines were not re-inspected until 2018. On April 21, 2020, Texas Gas stated in response to the finding of lack of inspection: “Engines not available to perform annual Gas Detection inspections due to maintenance in 2017.” Although the engines were out of service for part of 2017, the annual maintenance must still be performed because the units were returned to service.

Texas Gas contests this allegation because the alleged facts regarding the status of these gas detector units are incorrect. When compressor engines #1, #2, #3, #9, and #10 were repaired and upgraded in 2017, the gas detectors for these engines were permanently removed from service. They were not “returned to service” and they were not “re-inspected” in 2018. When the rehabilitated compressor engines were restored to service in late 2017 and early 2018, Texas Gas installed and commissioned new gas detector units. Texas Gas was not required to inspect the gas detector units permanently removed from service.

Texas Gas’s Dillsboro Compressor Station has 10 compressor engines. Each compressor engine has at least three gas detection units. During 2017, Texas Gas temporarily removed compressor engines #1, #2, #3, #9, and #10 from service for repairs and upgrades. This rehabilitation project required that each compressor engine be disconnected from gas supply and disassembled. On compressor engine #1, Texas Gas performed an engine foundation regrount, which entailed removing and repouring the engine’s concrete foundation.

The compressor engine rehabilitation project required that Texas Gas detach the gas detector units from the disassembled engines. These units were permanently removed because Texas Gas planned to install new gas detector units on the rehabilitated compressor engines. Permanently removing these units from service in 2017 terminated the regulatory obligation to inspect them under § 192.736(c) and Section 9040 of Texas Gas’s O&M Manual.

Texas Gas completed the repairs and upgrades on compressor engines #2, #3, #9, and #10 in late 2017. Before returning the rehabilitated engines to service, Texas Gas installed new gas detection units on each engine. A new gas detection unit also was installed on compressor engine

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13 Violation Report, Exhibit A at 310-311. For ease of reference, Section 9040 of Boardwalk’s O&M Manual is attached hereto as Attachment 1. See also 49 C.F.R. § 192.736.
14 Attachment 1 at 2.
15 Notice at 4 (emphasis added).
#1 when its rehabilitation and regout was completed in 2018. These are the units that were inspected in 2018.

The records documenting the commissioning and initial inspection of all of these new gas detection units, dated October and November 2017, and January 2018 are attached to this Response as Attachment 2.16

Throughout the 2017 compressor engine rehabilitation project, the gas detection and alarm system at the Dillsboro Compressor Station continued to function because compressor engines #4, #5, #6, #7, and #8 and their gas detector units remained in service. Records confirm that Texas Gas inspected the gas detection units associated with these compressor engines in August 2017 and that the gas detection and alarm systems were functional.17

Texas Gas did not fail to comply with Section 9040 of its O&M Manual and did not violate § 192.605(a). The Notice fails to set forth “the facts necessary to sustain a probable violation actually occurred.”18 This allegation and the proposed civil penalty must be withdrawn.

C. OPS Fails to Prove That Texas Gas Failed to Document Procedure Reviews Required Under § 192.605(b)(8).

Section 192.605(b)(8) requires an operator to have and follow a procedural manual for maintenance and normal operations, including procedures for “[p]eriodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.”19 Item 6 of the Notice asserts that “Texas Gas failed to determine the effectiveness and adequacy of its procedures based on a review of work performed during normal operations by its personnel.”20

The Notice states that, during the inspection, OPS “requested to review documentation relating to review of work performed for various procedures as required by Texas Gas procedure O&M Section 1010 ‘General Procedures.’”21 The Notice states that the material provided by Texas Gas, Form 1000-20: Compliance Manual Effectiveness Review, from the annual review for 2017, 2018, and 2019, “failed to document any assessment of work performed as part of the operations and maintenance procedures.”22 The Notice asserts that Texas Gas was “unable to

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16 Attachment 2 at 1, 2, 5, 6, & 7.
17 Violation Report, Exhibit E. For ease of reference, an excerpt of Exhibit E containing the 2017 inspection records is attached hereto as Attachment 3.
18 See, e.g., Alyeska Pipeline, 2009 WL 5538655 at *3 (quoting Schaeffer, 546 U.S. at 56-58); ExxonMobil, 2019 WL 3734516 at **4, 5 (ordering withdrawal of allegations where OPS failed to prove that Respondent engaged in conduct that would constitute a violation); Inland Corp., 2018 WL 2229407 at *3 (withdrawing alleged violation where testimony was contradictory and factual evidence provided by respondent did not support OPS’s claim); So. Star Cent. Gas Pipeline, 2011 WL 7006614 at *4 (finding the evidence insufficient to sustain the allegation).
19 49 C.F.R. § 192.605(b)(8).
20 Notice at 4.
21 Id. at 4-5.
22 Id. at 5.
present adequate information showing that it had periodically reviewed its procedures for
effectiveness based [on] consideration of the work performed by its personnel, and is in violation
of the regulation.”23

Item 6 must be withdrawn because the alleged conduct does not constitute a violation of
the regulation and because the information relied on by OPS does not support the allegation that
Texas Gas “failed to determine the effectiveness and adequacy of its procedures” by reviewing the
work performed by operator personnel during normal operations.24

O&M Section 1010, General Procedures, which is mentioned but not discussed in the
Notice, addresses two types of reviews of Texas Gas’s operating and maintenance procedures.25
O&M Section 1010 first addresses the reviews that are performed on an annual basis (not to exceed
15 months) as required under § 192.605(a).26

O&M Section 1010 then addresses the continual evaluation of the effectiveness and
adequacy of operations and maintenance procedures based on work performed by operator
personnel pursuant to § 192.605(b)(8).27

O&M Section 1020, O&M Management of Change (O&M Section 1020) contains further
procedures describing how revisions to operations and maintenance procedures are to be
conducted and specifically provides that “[t]he addi[ional] reviews may be required on a periodic basis
to ensure policies and procedures are effective and adequate.”28 O&M Section 1020 states that
the review by the Manager, Compliance Services shall “[v]erify that current policy/procedures
are consistent with practices currently being performed by employees. (This review shall include
examination of work associated with these procedures used in normal operation and
maintenance.)”29

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23 Id., Violation Report at 24.
24 Notice at 4.
25 Violation Report, Exhibit A at 38-40. For ease of reference, O&M Sections 1010 and 1020 of the Boardwalk O&M
Manual are attached hereto as Attachment 4.
26 Attachment 4 at 1 (stating “[t]his O&M shall be reviewed at least once per calendar year, but at intervals not
exceeding 15 months, by [Operations and Compliance Services]. Compliance Services shall use Form 1000-20:
Compliance Manual Effectiveness Review to document the review”).
27 O&M Section 1010 states:
“Procedures shall be evaluated any time there is a question of effectiveness and revisions issued in a
timely manner as needed. Reference manuals/documents shall be continually evaluated by employees
performing operations/maintenance activities on Boardwalk facilities. Any Employee who believes there
is a need to revise the current language in the manual should notify a Compliance Services representative
using the Compliance Services mailbox. Proposed changes shall be reviewed by Compliance Services
and may be referred to an appropriate O&M Review Task Group. Compliance Services shall make the
necessary revisions. Details for review and management of change for O&M are described in Section
1020: O&M Management of Change.” Attachment 4 at 2 (underlining added for emphasis; bold and
italics in original).
28 Attachment 4 at 2.
29 Id.
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O&M Section 1020 expressly instructs that “[i]f new policies, procedures, forms, or revisions to existing policies, procedures, or forms are required, Boardwalk employees shall complete Form 1000-10: Document Change Request Form.” 30 Employees who recommend changes to a procedure are instructed to redline the existing procedure to indicate the suggested revisions by submitting this form to the Compliance Services mailbox. O&M Section 1020 then describes the Management of Change process for evaluating and formally approving the suggested change. 31

The Notice relies on Form 1000-20, entitled Compliance Manual Effectiveness Review, to support the allegation that Texas Gas did not “document any assessment of work performed as part of the operations and maintenance procedures.” 32 As acknowledged in the Notice 33 and as is clear in O&M Section 1010, the purpose of Form 1000-20 is to document compliance with the requirement in § 192.605(a) to review procedures annually, not to exceed 15 months. 34 Form 1000-20 is not the form Texas Gas uses to document compliance with § 192.605(a)(8). Texas Gas uses Form 1000-10 to document changes made to procedures under § 192.605(a)(8). 35

OPS’s reference to Form 1000-20 is misplaced. PHMSA has failed to meet its burden of demonstrating that Texas Gas violated § 192.605(b)(8) because the Notice does not set forth “the facts necessary to sustain a probable violation actually occurred.” 36 The allegation in Item 6 must be withdrawn.

Even if PHMSA does not withdraw the allegation, the proposed compliance order must be withdrawn because it is unrelated to the alleged violation. The proposed compliance order would require that Texas Gas “provide a detailed written procedure to address the periodic review of work done to determine the effectiveness of its normal operations and maintenance procedures,” and to submit the written program to the Director and provide semi-annual reports on the results of the revised program until reviews of all procedures have been completed. 37

The Notice, however, does not allege that Texas Gas does not have a procedure for the required adequacy and effectiveness review of its procedures. The Notice’s reference to O&M

30 Id. at 3.
31 Id. at 3-4.
32 Notice at 5.
33 Id. at 5 (stating that the Compliance Manual Effectiveness Review documents Texas Gas’s annual reviews for the years 2017, 2018, 2019).
34 Attachment 4 at 1 (stating that “[t]his O&M shall be reviewed at least once per calendar year, but at intervals not exceeding 15 months, by Operations and Compliance Services. Compliance Services shall use Form 1000-20: Compliance Manual Effectiveness Review to document the review.”) (bold and italics in original).
35 Attachment 4 at 3 (representative samples of Form 1000-10s completed by employees recommending changes to Part 192 Operations and Maintenance procedures).
36 See, e.g., Alyeska Pipeline, 2009 WL 5538655 at *3 (quoting Schaeffer, 546 U.S. at 56-58); ExxonMobil, 2019 WL 3734516 at **4, 5 (ordering withdrawal of allegations where OPS failed to prove that Respondent engaged in conduct that would constitute a violation); Inland Corp., 2018 WL 2229407 at *3 (withdrawing alleged violation where testimony was contradictory and factual evidence provided by respondent did not support OPS’s claim); So. Star Cent. Gas Pipeline, 2011 WL 7006614 at *4 (finding the evidence insufficient to sustain the allegation).
37 Notice at 11.
Section 1010 is an explicit acknowledgement that the procedure exists. Nor does the Notice allege that either of Boardwalk's procedures, O&M Section 1010 and O&M Section 1020, are inadequate. There is no basis for this proposed compliance order.

OPS bears the burden of proving that a proposed remedy is appropriate. OPS has not met that burden because the proposed remedy is not relevant to the violation alleged in the Notice. The proposed compliance order must be withdrawn.


Section 192.619(a) prohibits the operation of "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" several limiting factors. One of these limiting factors is the "design pressure of the weakest element in the segment."

for steel pipe in pipelines being . . . uprated under Subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, one of the following pressures is to be used as design pressure: . . . . (ii) If the pipe is 12½ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

Item 8 of the Notice alleges that Texas Gas “determined a MAOP that exceeded the lowest pressure allowed under § 192.619 for its Bowling Green 4” Station,” and that “the MAOP did not reflect the limits required by § 192.619(a)(1)(ii), which is a maximum of 200 psig.” The Notice makes the following assertions.

From a review of records that established the Bowling Green MAOP, PHMSA identified that the station was uprated to an MAOP of 715 psig within a Class 1 location in 1977 according to 192 Subpart K requirements, specifically § 192.555(d)(2). Additionally, the uprate documentation did not include the pipe grade or recorded strength test after construction. At the time of the inspection, the class location of the Bowling Green station was Class 3. As such, the MAOP cannot be established under § 192.555(d)(2). Per OPS Advisory Bulletin – 1971-71-1, pipelines in Class 2, 3, and 4 locations must have their operating pressures confirmed or revised in accordance with § 192.611.

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38 Id. at 5.
39 See e.g., Slusser v. Commodity Futures Trading Comm’n, 210 F.3d 783, 787-88 (7th Cir. 2000); see also Gimbel v. Commodity Futures Trading Comm’n, 872 F.2d 196, 201 (7th Cir. 1989); Premex, Inc. v. Commodity Futures Trading Comm’n, 785 F.2d 1403, 1408-09 (9th Cir. 1986); Bosma v. U.S. Dep’t of Agriculture, 754 F.2d 804, 810 (9th Cir).
40 49 C.F.R. § 192.619(a).
41 Id. § 192.619(a)(1).
42 Id. § 192.619(a)(1)(ii).
43 Notice at 5-6.
44 Id.
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OPS also proposes to impose a $38,000 civil penalty\textsuperscript{45} and a proposed compliance order which states that “pertaining to the MAOP exceeding the lowest pressure allowed at its compressor stations, Texas Gas must . . . [r]eview all locations in the scope of the inspection for correct MAOP: Bowling Green, Calvert City, Covington, Dixie, Hanson, Kenton, Petersburg, Midland 3, West Greenville, and Slaughters areas,” and perform “adequate corrective actions at all locations identified by the review” and submit to the Director of the Central Region, a summary of the review and corrective actions of all locations.\textsuperscript{46}

Texas Gas contests Item 8. The Notice fails to explain how Texas Gas allegedly violates § 192.619(a)(1)(ii) or how the assertions in the Notice establish the alleged violation. The Violation Report states that “Texas Gas incorrectly determined the MAOP and are operating at this MAOP to date,”\textsuperscript{47} and that the violation started on December 31, 2009,\textsuperscript{48} but contains no explanation or supporting analysis. The multiple exhibits attached to the Violation Report also contain no analysis or explanation supporting the alleged violation.\textsuperscript{49}

As a result, Texas Gas is left guessing about the basis for the alleged violation. Section 190.207(b)(1) requires that a notice of probable violation include a “statement of the evidence upon which the allegations are based.”\textsuperscript{50} The Notice does not comply with this requirement and this item must be withdrawn.

If PHMSA does not withdraw Item 8 for failing to comply with the requirements of § 190.207(b)(1), then Texas Gas requests that the allegation be withdrawn for the reasons set forth below.

Texas Gas demonstrates first that the Notice incorrectly suggests that a pipeline’s MAOP established under § 192.555(d)(2) is automatically nullified by a class location change. Such a suggestion is not supported by any PHMSA decision, interpretation or guidance. This notion also is inconsistent with § 192.611 which describes the actions for an operator to take when hoop stress is not commensurate with class location. Second, the assertion in the Notice that Texas Gas was required to confirm or revise MAOP under § 192.611 is incorrect and inconsistent with the plain language of that regulation.

Texas Gas’s response to this item is based on its understanding of the assertions contained in the Notice. If Texas Gas’s understanding of OPS’s assertions is not correct, Texas Gas requests an opportunity to submit a supplemental response.

\textsuperscript{45} Id. at 9.
\textsuperscript{46} Id. at 11-12.
\textsuperscript{47} Violation Report at 35.
\textsuperscript{48} Id. at 33.
\textsuperscript{49} These exhibits contain copies of email and text correspondence between OPS and Texas Gas, the 1977 Uprate Report, a report prepared by Boardwalk Pipelines entitled, “Review of Relief Valve Set Point Calculations,” a chart showing MAOPs of various pipeline segments, and DOT Control Equipment Inspection Reports.
\textsuperscript{50} 49 C.F.R. § 190.207(b)(1).
1. The Uprate at Bowling Green No. 2 S.M.S. Established a Valid MAOP.

The facility at issue in Item 8 consists of short non-contiguous segments of small diameter steel piping totaling about 30 feet located within the Bowling Green No. 2 S.M.S. All of these individual piping segments are connected at both ends to fabricated facilities. The facility was constructed in 1965 and there is no record of a post-construction strength test. Wall thickness of the pipe is 0.322” and the yield strength is determined under § 192.107(b)(2). The post-1970 MAOP was 512 psig based on the five-year high operating pressure. When constructed, the piping was in a Class 1 location.

In 1977, Texas Gas performed an uprate on the Bowling Green No. 2 S.M.S. to increase MAOP from 512 psig to 715 psig, to be consistent with the MAOP of other components in the station. The uprate documentation shows that the 100% of Specified Minimum Yield Strength (SMYS) pressure is 1792 psig. In accordance with § 192.107(b)(2), Texas Gas used the default value of 24,000 psi for yield strength to calculate design pressure.

Texas Gas performed the uprate pursuant to § 192.555. As required under § 192.555(b), Texas Gas reviewed the design, operating and maintenance history of the pipeline segments to be uprated and replaced valves that had pressure ratings less than the proposed MAOP. Texas Gas performed the uprate under § 192.555(d)(2) which permits an operator to establish an increased MAOP for a previously untested pipeline segment in a Class 1 location if (1) testing the line is impractical, (2) the new MAOP will not exceed 80% of what would be allowed for a new line of the same design in the same location, and (3) the new MAOP is consistent with the condition of the pipeline segment and Part 192 design requirements. Pressure testing the pipeline segments was impractical because both ends of each segment connects to fabricated facilities within the meter station.

As required under § 192.555, Texas Gas increased pressure in increments. The highest pressure that was held and verified with a leak check was 715 psig. This value became the new uprated MAOP. This MAOP produces a hoop stress of 39.9% of SMYS.

In 2009, the population density near the Bowling Green station increased. Texas Gas determined that the class location had increased to Class 3. Section 192.611(a) states that “if the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must

51 The Bowling Green No. 2 S.M.S. is also referred to as “RBG 4.”
52 A diagram of Bowling Green No. 2 S.M.S. is attached hereto as Attachment 5.
53 Violation Report, Exhibit H. For ease of reference, the documentation for the 1977 Uprate at Bowling Green is attached hereto as Attachment 6. The 100% SMYS pressure of 1792 psig is based on the following calculation: (2*24000*0.322) / 8.625 in accordance with § 192.105(a).
54 49 C.F.R. § 192.107(b)(2).
55 Id. § 192.555.
56 Id. § 192.555(d)(2). See Attachment 6 at 9.
57 Attachment 5.
58 Attachment 6 at 1.
be confirmed or revised” in accordance with one of several requirements.\textsuperscript{59} Because the 39.9% SMYS hoop stress associated with Bowling Green’s MAOP of 715 psig is commensurate with the 0.50 design factor of the Class 3 location, and the line was in satisfactory physical condition, Texas Gas was not required to confirm or revise MAOP under § 192.611.


The Notice states that “[a]t the time of the inspection, the class location of the Bowling Green station was Class 3. As such, the MAOP cannot be established under § 192.555(d)(2).”\textsuperscript{60} Texas Gas’s understanding of this statement is that OPS is asserting that, when the class location increased from a Class 1 to a Class 3, MAOP at Bowling Green No. 2 S.M.S. was invalidated because it was established under § 192.555(d)(2).\textsuperscript{61} This assertion is echoed in the Violation Report’s claim that the alleged violation began on December 31, 2009, the same year as the class location change.\textsuperscript{62} The Notice does not explain the basis for this assertion or provide any supporting evidence. Additionally, the Notice does not explain the relevance of observations regarding pipe grade or a post-construction pressure test.\textsuperscript{63}

The suggestion that an MAOP established under § 192.555(d)(2) is automatically invalidated by a class location change is incorrect. PHMSA does not cite to any supporting regulation, PHMSA decision or guidance. This suggestion also is inconsistent with § 192.611 which describes the actions for an operator to take when the hoop stress associated with a pipeline’s MAOP is not commensurate with class location after a class location increase.\textsuperscript{64} Section 192.611 allows an operator 24 months to take those actions, regardless of the basis for the existing MAOP.\textsuperscript{65} If hoop stress remains commensurate with class location after a class location change, § 192.611 does not apply and an operator is not required to confirm or revise MAOP.\textsuperscript{66} If MAOP were automatically invalidated after a class location change, § 192.611 would serve no purpose.

The purpose of § 192.611 and the procedures it sets forth undermine any suggestion that an MAOP determined under § 192.555(d)(2) is rendered invalid solely as a result of a class location change. Any suggestion that Texas Gas was not permitted to rely on the default yield strength value of 24,000 psi when calculating the design pressure of the Bowling Green No. 2 S.M.S. cannot be reconciled with § 192.105 and § 192.107 which expressly permit use of this value in the calculation.\textsuperscript{67} Establishing MAOP without a pressure test is expressly permitted under § 192.555(d)(2). The validly established MAOP of the Bowling Green No. 2 S.M.S. was not automatically invalidated by the class location change.

\textsuperscript{59} 49 C.F.R. § 192.611 (emphasis added).
\textsuperscript{60} Notice at 6.
\textsuperscript{61} Id. at 6, stating that, “[a]t the time of the inspection, the class location of the Bowling Green station was Class 3. As such, the MAOP cannot be established under § 192.555(d)(2).”
\textsuperscript{62} Violation Report at 33.
\textsuperscript{63} Notice at 6.
\textsuperscript{64} 49 C.F.R. § 192.611(a).
\textsuperscript{65} Id. § 192.611(d).
\textsuperscript{66} Id. § 192.611(a).
\textsuperscript{67} Id. §§ 192.105 and 192.107(b)(2).
3. **Texas Gas Was Not Required to Confirm or Revise MAOP Under § 192.611.**

The Notice also states that Texas Gas was required to confirm or revise MAOP under § 192.611. This assertion is incorrect and misconstrues the regulation.  

The Notice ignores the fact that § 192.611 applies only “[i]f the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location.” If the hoop stress corresponding to a pipeline’s MAOP is commensurate with the class location, confirming or revising MAOP is not required.

This limiting language is important. It means that § 192.611 can apply only to pipelines with MAOPs producing hoop stresses of more than 40% SMYS because the design factor for Class 4 locations, the most densely populated class locations, is 0.40. The design factors for all other class locations are higher than 0.40. Pipelines with MAOPs producing hoop stresses lower than 40%, like the Bowling Green No. 2 S.M.S., are always commensurate with the class location and are not subject to § 192.611.

The hoop stress corresponding to the MAOP of the Bowling Green No. 2 S.M.S. is 39.9% SMYS. It is commensurate with the Class 3 location design factor of 0.50. The Bowling Green No. 2 S.M.S. is not subject to §192.611 and Texas Gas was not required to confirm or revise the pipeline’s MAOP or perform any of the other measures described in § 192.611, including an MAOP reduction, performing a Subpart J pressure test, or pipe replacement.

The OPS Advisory Bulletin – 1971-71-1 relied on in the Notice does not demonstrate otherwise. This 1971 advisory bulletin, released a little over one year after issuance of the original federal pipeline safety regulations in 1970, addressed the following question: “[w]hat is the effect of the ‘grandfather’ clause in Sec. 192.619(c) on the requirements in Sections 192.607 and 192.611 that a maximum allowable operating pressure (MAOP) of a pipeline which is not commensurate with its present class location must be confirmed or revised in accordance with Sec. 192.611?”

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68 Notice at 6, stating “Per OPS Advisory Bulletin – 1971-71-1, pipelines in Class 2, 3, and 4 locations must have their operating pressures confirmed or revised in accordance with § 192.611.”

69 49 C.F.R. § 192.611(a).

70 Id. § 192.111(a).

71 Id.

72 Office of Pipeline Safety, Advisory Bulletin No. 71-1, 3 (Sept. 1971). This 1971 advisory bulletin is not included in the Violation Report. For ease of reference and to ensure that a copy is included in the case file, a copy is attached hereto as Attachment 7.

73 Attachment 7 at 3. (emphasis added).
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The version of § 192.607 referenced in this question was adopted in the original 1970 federal pipeline safety regulations and has been repealed.\(^\text{74}\) Original § 192.607 required that operators confirm class locations of all pipelines with MAOPs producing hoop stresses of more than 40% SMYS by performing class location studies.\(^\text{75}\) If the hoop stress of a pipeline was not commensurate with class location, an operator was required to confirm or revise MAOP under § 192.611. Operators were required to complete their initial determinations by December 1974.\(^\text{76}\)

The 1971 advisory bulletin addressed the relationship between these requirements and § 192.619(c) which allows an operator to establish MAOP for a pipeline based on the highest operating pressure the line experienced during the five years before 1970, even if the hoop stress associated with that MAOP exceeds the limitations of the regulations, \textit{i.e.}, is not commensurate with class location. The advisory bulletin stated that § 192.619(c) is constrained by § 192.611 and explained that, because § 192.611 does not mention pipe in Class 1 locations and its predecessor provision in the pre-1970 ANSI B31.8 code excluded Class 1 pipelines, § 192.611 is meaningfully applied only to pipe in Class 2, 3, and 4 locations. The advisory bulletin stated that such pipelines “must have their operating pressures confirmed or revised in accordance with § 192.611.”\(^\text{77}\)

Contrary to the assertion in the Notice, this advisory bulletin does not mean that all pipe in Class 2, 3, and 4 locations are always subject to § 192.611. Such an interpretation would moot the language in § 192.611(a) limiting its application to pipelines where hoop stress associated with MAOP is not commensurate with class location.\(^\text{78}\) The question addressed in the advisory bulletin expressly acknowledges this limitation.\(^\text{79}\) The advisory bulletin states that confirming and revising MAOP is to be performed “in accordance with § 192.611,” which means that this provision must be interpreted consistently with its limited applicability. As explained above, the practical effect of the applicability language in § 192.611(a) is that § 192.611 applies only to pipelines with hoop stresses higher than 40% SMYS.

OPS provides no evidence proving that the MAOP of the Bowling Green No. 2 S.M.S. exceeds the limitation set forth in § 192.619(a)(1)(ii) and must be limited to 200 psig. Texas Gas properly established MAOP under § 192.555(d)(2). That MAOP was not invalidated in 2009 by a class location increase. Texas Gas was not required to confirm or revise MAOP under § 192.611 because the hoop stress associated with the MAOP of the Bowling Green pipeline is commensurate with the Class 3 location.


\(^\text{77}\) Attachment 7 at 4.

\(^\text{78}\) 49 C.F.R. § 192.611(a).

\(^\text{79}\) Attachment 7 at 4.
Item 8 of the Notice must be withdrawn. The Notice fails to include a “statement of the evidence upon which the allegations are based” in violation of § 190.207(b)(1).\(^{80}\) OPS misconstrues these regulatory requirements, and has not met its burden of proving a violation of § 192.619(a)(i)(ii).\(^{81}\) The proposed compliance order and proposed civil penalty also must be withdrawn.

E. OPS Has Not Proven that Texas Gas Performed Leakage Surveys With Improper Equipment in Class 3 Locations.

Section 192.706(a) requires that an operator perform leakage surveys of unodorized transmission lines “[i]n Class 3 locations, at intervals not exceeding 7½ months, but at least twice each calendar year” using leak detector equipment.\(^{82}\) Item 11 of the Notice alleges that Texas Gas “failed to conduct leakage surveys on Class 3 transmission lines that transported gas without an odor or odorant using leak detector equipment,” in violation of § 192.706(a).\(^{83}\)

The Notice states that between 2017 and 2020, Texas Gas personnel performed leakage surveys at 12 locations on its system using 5 different “improper leak detectors.” The Notice asserts that, based on a review of the detectors’ manufacturer design specifications, OPS found that the devices were “not designed for detecting leaks from underground pipe” but “were designed for detection of leaks in above-ground pipe or for higher concentrations of gas to detect hazardous or explosive atmospheres to ensure personnel safety.”\(^{84}\) The Notice also alleges that “Texas Gas’ own personnel acknowledged that the instruments in use were not appropriate for leak detection on the right of way.”\(^{85}\)

The proposed compliance order would require that Texas Gas perform an adequate leakage survey at all sites identified in the Notice and report the results to the Director of PHMSA’s Central Region.\(^{86}\) The Notice also proposes a $138,100 civil penalty.\(^{87}\)

This item must be withdrawn. OPS has not met its burden of proving that the leak detection equipment listed in the Notice is improper or inappropriate for detecting leaks from a buried pipeline in a right of way. The Notice does not allege that Texas Gas failed to detect a leak or that a leak incident occurred. OPS provides no technical analysis explaining why the leak detectors

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\(^{80}\) 49 C.F.R. § 190.207(b)(1).
\(^{81}\) Air Prods. & Chems., 2015 WL 6758819 at *3 (withdrawing alleged violation because PHMSA did not produce “any evidence to support its position” and thereby did not meet its burden of proof); ExxonMobil, 2015 WL 780721 at *12 (finding that PHMSA failed to meet burden of proving that certain measures were required under regulations); So. Star Cent. Gas Pipeline, 2011 WL 7006614 at *4 (finding the evidence insufficient to sustain the allegation); Golden Pass, 2011 WL 1919517 at *5 (finding that PHMSA did not meet its burden of proving that its interpretation of regulatory language was correct).
\(^{82}\) 49 C.F.R. § 192.706(a).
\(^{83}\) Notice at 7.
\(^{84}\) Id.
\(^{85}\) Id.
\(^{86}\) Id. at 12.
\(^{87}\) Notice at 9; PHMSA, Office of Pipeline Safety, Proposed Civil Penalty Worksheet, Texas Gas Transmission, CPF No. 3-2022-072-NOPV (Dec. 20, 2021).
used by Texas Gas are not designed for detecting leaks from pipe located below ground and does not explain the concentration levels a leak detector must be capable of measuring in a pipeline right of way or why the leak detectors identified in the Notice cannot detect gas at those concentrations.

OPS does not demonstrate that the leakage surveys identified in the Violation Report were performed using the equipment alleged to be improper or that they were performed in Class 3 locations.

1. **OPS Has Not Proven That the Listed Leak Detection Equipment Is Improper.**

The Notice alleges that Texas Gas used the following “improper” leak detectors to perform leakage surveys on unodorized Class 3 transmission lines: TIF 8800X, MSA Altair 4X, Gas Trac NGX-6, Sperian Multipro, and Leakator.88 OPS alleges that Texas Gas used this equipment at 12 locations: Jeffersontown, Hardinsburg, Leesville, Dillsboro, Bowling Green, Calvert City, Petersburg, West Greenville, Hanson, Slaughters, Bastrop, and Isola.89

OPS has not met its burden of proving that any of the identified leak detection equipment is improper. Section 192.706 is a performance-based regulation that requires the use of “leak detector equipment” but does not specify any criteria for that equipment.90 PHMSA decisions and guidance contain no suggestion that any particular leak detector is approved or disapproved for leakage surveys as long as the chosen leak detection method is effective.91 PHMSA has consistently held that the performance-based nature of this regulation leaves the choice of equipment up to the discretion and engineering judgment of the operator.92

In a recent case requiring withdrawal of an alleged violation of § 192.706(a), PHMSA explained the kind of evidence that is required to establish a violation of this regulation:

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88 Notice at 7.
89 Id. at 7; Violation Report at 51.
91 See, e.g., Tennessee Gas Pipeline, 2019 WL 7943664 at **4, 5 (withdrawing alleged violation of § 192.706 where OPS did not meet its burden of proving that Respondent’s chosen leak detection method was ineffective and a violation of § 192.706); Letter of Richard D. Huriaux, P.E., Manager, Regulations, OPS, to Mr. Richard Motsinger, Pragmatics, Interpretation PI-01-0104 (Apr. 3, 2001) (stating OPS was “puzzled” why some believed that leak surveys needed to be conducted with a particular kind of equipment and that “[t]he DOT pipeline safety regulations at 49 C.F.R. § 192.706 and § 192.723 only require that leakage be conducted ‘using leak detector equipment’ . . . Our leak detection regulations are performance-based . . . The regulations do not mandate the use of any specific type of detection equipment.”)
92 Interpretation PI-01-0104 (stating OPS was “puzzled” why some believed that leak surveys needed to be conducted with a particular kind of equipment). Letter of James C. Thomas, Southwest Regional Director, OPS, to Ms. Jayne Fletcher, Airwave Environmental Technologies, Interpretation PI-95-054 (Dec. 5, 1995) (refusing to opine on a particular kind of technology for gas pipeline surveillance, stating “[i]t is our policy not to issue general acceptance for new technologies but rather leave it to each individual operator to review the available technologies and determine if they are adequate.”).
In the absence of a reason to believe that [Respondent’s leak detection] method was ineffective, such as one or more leak incidents, it is OPS [Office of Pipeline Safety] that has the burden of proof in showing that Respondent’s methods were not effective. The 2009 Letter of Interpretation cited by OPS does not shift this burden in this proceeding. In the context of proving a code violation for ineffective leak detection where no leaks had occurred, it was incumbent on OPS to demonstrate that underground migration patterns or other factors made Respondent’s method ineffective. OPS did not provide any technical analysis along these lines and no history of a leak incident was shown.93

OPS has not identified any leak that Texas Gas failed to detect and has not identified any leak incidents. OPS has the burden of showing that Texas Gas’s leak detection equipment was not effective under § 192.706(a) and has not met that burden.

The Notice alleges that, based on a review of the leak detector manufacturer’s design specifications, the leak detection devices identified in the Notice “were designed for detection of leaks in above-ground pipe or for higher concentrations of gas to detect hazardous or explosive atmospheres to ensure personnel safety.”94 OPS provides no technical analysis to support this statement. For example, the Notice does not explain why the leak detectors are not designed to detect leaks from pipe located below ground. The Notice also does not explain the concentration levels a leak detector must be capable of measuring in a pipeline right of way or why the leak detectors identified in the Notice cannot detect gas at those concentrations. For the GasTrac detector, OPS provides only a user manual, not manufacturer’s design specification.95

The Notice’s distinction between leak detectors for aboveground pipe and buried pipe has no basis in the regulation, regulatory guidance, PHMSA case law or industry literature.96 It is the nature of any leak on a buried pipeline that the gas will make its way through the ground cover over a pipeline where the gas can be detected by any number of methods including sight (because of dead vegetation or surface bubbling), sound, or leak detection equipment. Detection by these methods, which are widely used in the pipeline industry and often used in conjunction with one another when personnel walk the right of way, occurs when the leak reaches the atmosphere, regardless of whether the pipe is aboveground or below. Texas Gas’s pipeline is buried below ground and the equipment is held at ground level to detect if methane is reaching the surface. Leak detection equipment is not used to detect methane below the ground.

The email from MSA, the manufacturer of the Altair 4X and 4RX leak detectors does not support the allegation that the MSA Altair 4X is not appropriate for detecting leaks on the right of

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93 *Tennessee Gas Pipeline*, 2019 WL 7943664 at **4, 5 (withdrawing alleged violation of § 192.706 because OPS did not meet its burden of proving a violation).
94 Notice at 7.
95 Violation Report, Exhibit K.
96 A review of industry literature as well as PHMSA guidance, regulatory history, and public meeting materials revealed no previously articulated distinction between leak detection devices for aboveground and belowground piping.
way. 97 That email, which is contained in the Violation Report, states that the Altair 4RX model is not meant for pipes that are fully underground. 98 OPS has not, however, alleged that the Altair 4RX model inadequate and Texas Gas does not identify this model as equipment used at any of the locations identified in the Notice.

Finally, OPS’s reliance on a statement allegedly made by Texas Gas’s Director of Asset Integrity during the inspection carries no weight. OPS has provided no information regarding the nature or scope of this employee’s responsibilities, including whether the employee has any responsibility for performing leakage surveys or supervising employees who perform them.

OPS has not satisfied its burden of demonstrating a violation of § 192.706 and this item must be withdrawn. 99 The proposed compliance order, which would require that Texas Gas perform “adequate” leakage surveys at all sites identified in the Notice and report the results to the Director, 100 also must be withdrawn.

2. OPS’s Evidence Does Not Establish That Texas Gas Performed Leakage Surveys in Class 3 Locations Using Leak Detection Equipment Alleged to Be Improper.

Based on a document with a file name “Leak Equipment Count,” the Violation Report asserts that, during 2017, 2018, 2019, and 2020, Texas Gas performed 92 leakage surveys in Class 3 locations using improper leak detection equipment. 101 For each year, the Leak Equipment Count lists the pipelines (identified with a Texas Gas line number) on which Texas Gas performed leakage surveys in 10 of the 12 locations listed in the Notice. 102

The Violation Report asserts that these 92 instances are supported by Texas Gas’s DOT Land Patrol Survey and Leak Detection Survey Reports (Survey Reports), which document Texas Gas’s leakage surveys, and work orders associated with each leak survey. 103 The Violation Report also states that the “[i]nstances of violation are based on review of work orders and operator

97 Violation Report, Exhibit K. For ease of reference, this email is attached hereto as Attachment 8. (Email from Gabby (MSA Customer Service) to Eric Heck, General Engineer, PHMSA Central Region (Feb. 22, 2021)).
98 Attachment 8 at 1.
99 **Tennessee Gas Pipeline, 2019 WL 7943664 at **4, 5 (withdrawing alleged violation of § 192.706 where OPS did not meet its burden of proving that Respondent’s chosen leak detection method was ineffective and a violation of § 192.706); ExxonMobil, 2019 WL 3734516 at **4, 5 (ordering withdrawal of allegations where OPS failed to prove that Respondent engaged in conduct that would constitute a violation); Air Prods. & Chems., 2015 WL 6758819 at *3 (withdrawing alleged violation because PHMSA did not produce “any evidence to support its position” and thereby did not meet its burden of proof); So. Star Cent. Gas Pipeline, 2011 WL 7006614 at *4 (withdrawing allegation because the evidence was insufficient to sustain the allegation).
100 Notice at 6.
101 Violation Report, Exhibit K. For ease of reference, OPS’s Leak Equipment Count is attached hereto as Attachment 9.
102 The Leak Equipment Count does not list any leakage surveys for Dillsboro and West Greenville. Id. at Attachment 9.
103 Violation Report at 51. The Violation Report states that the Survey Reports “document if the survey was an instrumented survey or not for class 3 locations with a work order associated to the location. The work orders list the instrument used in the field and it was found that those devices were not adequate.”
provided equipment list.”¹⁰⁴ According to the Violation Report, the equipment list provided by Texas Gas is “a compiled list of devices used out in the field for 2020 for Class 3 and 4 leak surveys” and lists devices “that are not adequate.”¹⁰⁵

To satisfy its burden of proving that Texas Gas violated § 192.706(a), OPS must prove “all elements of the proposed violation.”¹⁰⁶ Specifically, for each of the 92 alleged instances, OPS must demonstrate that Texas Gas (1) conducted a leakage survey using an improper leak detection device (2) on a line in a Class 3 location. Instances that are not supported by evidence must be withdrawn.¹⁰⁷

Texas Gas demonstrates below that the 92 leakage surveys listed in the Leak Equipment Count are not substantiated by the Survey Reports, work orders or the Texas Gas-provided list of leak detection equipment. For 80 instances alleged to have occurred in 2020, OPS does not provide either a Survey Report or a work order, relying solely on Texas Gas’s list of leak detection equipment. This list, however, does not identify the pipelines on which the equipment was used or specify any class locations where the equipment was used. It does not corroborate the Leak Equipment Count.

The other 12 leakage surveys listed in the Leak Equipment Count, which were conducted in 2017, 2018, and 2019, either lack documentation or the information provided does not establish that the leakage survey was conducted with leak detection equipment alleged to be improper or that the leakage survey was performed in a Class 3 location.

Below, Texas Gas demonstrates that for each of the 92 leakage surveys listed in the Leak Equipment Count, OPS fails to prove that Texas Gas used the leak detection equipment listed in the Notice on a Class 3 pipeline.

**Bastrop.** OPS’s Leak Equipment Count alleges that in 2017, Texas Gas performed a leakage survey on line EIS 18-1TT 25+4699, 26+2851 using improper leak detection equipment.¹⁰⁸ Texas Gas’s 2017 Survey Report for Bastrop shows that two leakage surveys were

¹⁰⁴ Violation Report at 56 & Exhibit K. The work orders and Texas Gas’s Survey Reports are contained in OPS files named IS 3020 Class 3 Leak Survey Records. pdf and 17445_Lean.pdf. For ease of reference, they are attached in multiple attachments to this Response. The Texas Gas-provided equipment list also is contained in Exhibit K and has the file name bwp_gas_detector_lists.pdf. For ease of reference, the equipment list is attached hereto as Attachment 10.
¹⁰⁵ Violation Report at 52. Texas Gas notes that, of the leak detection equipment listed in Attachment 9, only some are alleged to be inadequate.
¹⁰⁶ ANR Pipeline, 2012 WL 7177134 at *3 (withdrawing alleged violation because evidence did not establish all elements of the alleged violation); CITGO Pipeline, 2011 WL 7517716 at *5 (withdrawing alleged violation because evidence did not prove all of the elements necessary to sustain the violation).
¹⁰⁷ ANR Pipeline, 2012 WL 7177134 at *3; CITGO Pipeline, 2011 WL 7517716 at *5. See also, ExxonMobil Pipeline, 2019 WL 3734516 at **4, 5 (withdrawing allegation because PHMSA’s evidence did not establish a violation); Air Prods. & Chems., 2015 WL 6758819 at *3 (withdrawing alleged violation because PHMSA did not produce “any evidence to support its position” and thereby did not meet its burden of proof); So. Star Cent. Gas, 2011 WL 7006614 at *4 (finding the evidence insufficient to sustain the allegation).
¹⁰⁸ Attachment 9 (highlighting in original).
performed on this pipeline. One was performed on January 6, 2017; the other on July 7, 2017. The only work order provided for Bastrop, Work Order No. 1253806, documents the leakage survey performed on January 6, 2017, which was more than 5 years before the Notice was issued on January 21, 2022. The statute of limitations bars any allegation regarding the January 6, 2017 leakage survey.

PHMSA is subject to the general federal statute of limitations, 28 U.S.C. § 2462 which states that “an action, suit or proceeding for the enforcement of any civil fine, penalty, or forfeiture, pecuniary or otherwise, shall not be entertained unless commenced within five years from the date when the claim first accrued.” Section 2462 applies to civil penalty enforcement actions of federal administrative agencies, including PHMSA. The action here accrued in January 6, 2017 when Texas Gas performed the leakage survey which is more than 5 years before the Notice was issued on January 21, 2022. Enforcement with respect to this leakage survey and the proposed civil penalty are precluded as a matter of law.

With respect to the leakage survey performed on July 7, 2017, OPS provides no work order and the Survey Report does not indicate the leak detection equipment used. It is impossible know, based on the information provided in the Violation Report, which leak detection equipment was used to perform this leakage survey. OPS has failed to demonstrate that Texas Gas performed a leakage survey at Bastrop using leak detection equipment alleged to be inadequate.

Jeffersontown. OPS alleges that in 2019 and 2020, Texas Gas performed a total of 13 leakage surveys using improper leak detection equipment on 6 lines at Jeffersontown, 1 in 2019 and 21 in 2020.

According to OPS’s Leak Equipment Count, in 2020 Texas Gas performed 2 leakage surveys on Asset No. 105284-LINE, MLS 26-1TT. The Violation Report provides no Survey Report or work order for either of these 2 surveys. The Violation Report, however, does provide a work order for a 2018 leakage survey performed on this pipeline. Work Order No. 1455877 indicates that this line is in a Class 1 and Class 2 Location, not a Class 3 Location. This alleged improper leakage survey is unsubstantiated by the evidence.

For the remaining 10 leakage surveys listed for 2020, OPS provides no Survey Reports or work orders, relying solely on Texas Gas’s list of leak detection equipment. This list indicates that

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109 Violation Report, Exhibit K. For ease of reference, Texas Gas’s 2017 Survey Report for Bastrop is attached hereto as Attachment 11.
110 Attachment 11 at 3.
113 3M Co., 17 F.3d at 1462.
114 See Attachment 11.
115 Attachment 9.
116 Id.
117 Violation Report, Exhibit K. For ease of reference, Work Order No. 1455877 is attached hereto as part of Attachment 12 at 1.
2 types of leak detection equipment were used at Jeffersontown: the Focused Photonics Model RLDG-100 and the MSA Altair 4x.\(^\text{118}\)

OPS does not allege that the Focused Photonics Model RLDG-100 is an improper leak detector and the Violation Report contains no information on this equipment. The Texas Gas equipment list does not identify individual pipelines or any class locations and does not state the leak detection equipment used on any specific line. It is impossible to know, based on the information provided in the Violation Report, which leak detection device was used to perform leakage surveys on the lines listed in OPS’s Leak Equipment Count or whether the devices were used in Class 3 locations.

Finally, for the leakage survey conducted in 2019 on Line 328509, MLS 30-1TT, OPS provides Work Order No. 1601033, which indicates that Texas Gas used leak detection equipment identified as “Altair,” and a 2019 Survey Report.\(^\text{119}\) Neither the work order nor the Survey Report identifies the full model name or number of the leak detection equipment, so it is not known whether it is the same Altair detector that the Notice alleges is improper. The work order and the Survey Report fail to establish that Texas Gas conducted leakage surveys using alleged improper leak detection equipment on a Class 3 pipeline at Jeffersontown.

\textit{Hanson}. OPS alleges that, in 2020, Texas Gas performed 2 leakage surveys using improper equipment.\(^\text{120}\) OPS provides no Survey Reports or work orders documenting these surveys, relying solely on the equipment list provided by Texas Gas which identifies 2 leak detectors used at Hanson: the Multipro-Multi Gas Detector and the MSA Altair 4x.\(^\text{121}\)

OPS does not allege that the Multipro-Multi Gas Detector is an improper leak detector and provides no information on it.\(^\text{122}\) The Texas Gas equipment list does not identify individual pipelines or their class locations and does not indicate which leak detector was used to survey any specific line. It is impossible to know, based on the information provided in the Violation Report, which leak detection device was used on the lines listed in OPS’s Leak Equipment Count or whether the devices were used in a Class 3 location.

OPS has failed to demonstrate that Texas Gas conducted leakage surveys on a Class 3 pipeline at Hanson using improper leak detection equipment.

\textit{Calvert City}. OPS alleges that in 2020, Texas Gas performed 22 leakage surveys using improper leak detection equipment on 11 pipelines.\(^\text{123}\) The Violation Report contains no Survey Report or work order for the surveys performed at this location. The Texas Gas equipment list

\begin{itemize}
  \item \(^{118}\) Attachment 10 at 1.
  \item \(^{119}\) Violation Report, Exhibit K. For ease of reference, Work Order No. 16010033 and Texas Gas’s 2019 Survey Report for Jeffersontown are included as part of Attachment 12.
  \item \(^{120}\) Attachment 9.
  \item \(^{121}\) Attachment 10 at 1.
  \item \(^{122}\) Exhibit K of the Violation Report contains information on a “Sperian Multipro detector,” but neither the Notice nor the Violation Report indicates whether it is the same as the Multipro Multi Gas Detector.
  \item \(^{123}\) Attachment 9.
\end{itemize}
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indicates that the device used at Calvert City in 2020 was a Bacharach UV 1035.\textsuperscript{124} OPS does not allege that this leak detection device is improper.\textsuperscript{125} OPS has failed to prove that Texas Gas conducted leakage surveys on a Class 3 pipeline using improper leak detection equipment at Calvert City.

\textbf{Leesville.} OPS’s Leak Equipment Count alleges that in 2018 and 2020, Texas Gas used improper equipment to perform 3 leakage surveys on Line 102239, BEI 20-1TT, one in 2018 and two in 2020.\textsuperscript{126}

For the leakage surveys performed in 2020, OPS supports its allegation by relying solely on the Texas Gas list of leak detection equipment\textsuperscript{127} which, according to the Violation Report, lists leak detection equipment used in both Class 3 and Class 4 locations.\textsuperscript{128} This list does not identify specific lines surveyed, indicate which lines listed in the Leak Equipment Count are in a Class 3 location, or establish that the listed equipment was used in a Class 3 location. The Texas Gas equipment list does not corroborate the Leak Equipment Count for the 2020 leakage surveys.

For the 2018 leakage survey on Line 102239, BEI 20-1TT, the Violation Report includes the 2018 Survey Report for Leesville and Work Order No. 1401451. Neither of these documents lists this line.\textsuperscript{129}

OPS has failed to meet its burden of demonstrating that Texas Gas conducted leakage surveys on a Class 3 line using improper leak detection equipment at Leesville.

\textbf{Hardinsburg.} OPS alleges that in 2018, 2019, and 2020, Texas Gas performed a total of 12 leakage surveys on 2 different pipelines using improper equipment.\textsuperscript{130} The Violation Report contains Survey Reports only for the 2018 and 2019 surveys and provides no work orders.\textsuperscript{131}

For the 8 leakage surveys performed in 2018 and 2019, the Survey Reports do not indicate the equipment used.\textsuperscript{132} The Violation Report includes a one-page document entitled “Hardinsburg Patrols” which contains the following statements:

5/15/18 & 11/13/18 – Class 3 Ground Patrol. Used TIF 8800 Sniffer No Calibration.

\textsuperscript{124} Attachment 10 at 1.  
\textsuperscript{125} See Notice at 7.  
\textsuperscript{126} Attachment 9.  
\textsuperscript{127} Attachment 10 at 1.  
\textsuperscript{128} Violation Report at 52.  
\textsuperscript{129} Violation Report, Exhibit K. For ease of reference, Texas Gas’s 2018 Survey Report for Leesville and Work Order No. 10401451 are attached hereto as Attachment 13. The "Land Patrol Report" for Leesville identifies only leak surveys performed in January 2017 and is not relevant to leakage surveys performed in 2018 and 2020. Violation Report, Exhibit K.  
\textsuperscript{130} Attachment 9.  
\textsuperscript{131} Violation Report, Exhibit K. For ease of reference, Texas Gas’s 2018 and 2019 Survey Reports and the document named “Hardinsburg Patrols” is attached hereto as Attachment 14.  
\textsuperscript{132} See Attachment 14 at 1-4.
5/15/19 & 11/15/19 Insp. Class 3. Ground Patrol. Used TIF 8800 Sniffer is a gas detector that does not require calibration.133

This document does not establish that Texas Gas performed leakage surveys at Hardinsburg using leak detection equipment alleged to be improper. The reference above to “TIF 8800” does not specify a model number. Based on the Texas Gas list of equipment, the model used at Hardinsburg is the TIF 8800A. The Notice alleges that the TIF 8800X is improper.134

For the 4 leakage surveys performed in 2020, OPS relies on the Texas Gas equipment list which does not identify lines that were surveyed in Hardinsburg, does not establish that the lines identified in the Leak Equipment Count are in a Class 3 location, and does not prove that the listed equipment was used in a Class 3 location.135 The Texas Gas equipment list does not corroborate the information in the Leak Equipment Count for the 2020 leakage surveys.

OPS has failed to satisfy its burden of proving that Texas Gas conducted leakage surveys on Class 3 lines using improper leak detection equipment at Hardinsburg.

**Bowling Green.** OPS alleges that in 2020, Texas Gas performed 14 leakage surveys using improper devices on 7 lines.136 The Violation Report contains no Survey Reports or work orders documenting these leakage surveys. OPS relies solely on the Texas Gas equipment list which does not specify lines that were surveyed at Bowling Green.137 The Texas Gas equipment list does not corroborate the information in the Leak Equipment Count.

**Petersburg.** OPS alleges that in 2020, Texas Gas performed a total of 12 leakage surveys using improper equipment on 6 lines.138 The Violation Report contains no Survey Report or corresponding work order documenting any of the listed leakage surveys. The only support provided is the Texas Gas equipment list which lists leak detection equipment used in both Class 3 and Class 4 locations.139 The list does not identify pipelines that were surveyed in Petersburg, verify that the lines identified in OPS’s Leak Equipment Count are in a Class 3 location, or establish that the listed equipment was used in a Class 3 location.140 The Texas Gas equipment list does not corroborate the information in the Leak Equipment Count.

OPS has not proven that Texas Gas performed leakage surveys on Class 3 lines using improper leak detection equipment at Petersburg.

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133 Attachment 14 at 5.
134 Notice at 7.
135 Attachment 10 at 1.
136 Attachment 9.
137 Attachment 10 at 1.
138 Attachment 9.
139 Attachment 10; Violation Report at 52.
140 Attachment 10 at 2.
Slaughters. OPS alleges that in 2020, Texas Gas performed a total of 12 leakage surveys on 6 lines using improper equipment.\textsuperscript{141} OPS provides no Survey Reports or work orders documenting these leakage surveys. OPS relies solely on the Texas Gas equipment list which identifies the leak detection equipment used in both Class 3 and Class 4 locations.\textsuperscript{142} While this list indicates that Texas Gas used the TIF 8800X and MSA Altair 4x detectors at Slaughters, the list does not identify the pipelines that were surveyed in Slaughters, verify that the lines identified in the Leak Equipment Count are in Class 3 locations, or establish that the listed equipment was used in a Class 3 location. The Texas Gas equipment list does not corroborate the information in the Leak Equipment Count.

Greenville-Isola. OPS alleges that in 2018, Texas Gas performed a leakage survey using improper equipment on one pipeline at Greenville-Isola.\textsuperscript{143} The Violation Report includes a Survey Report for the identified line and Work Order No. 1415494 which states that the leak detector used was a Bacharach Leakator 10.\textsuperscript{144} Neither of these documents establishes that this pipeline is in a Class 3 location.\textsuperscript{145} In addition, the Notice alleges that the “Leakator,” not the “Leakator 10” is an improper leak detection device.\textsuperscript{146} It is not clear if these are the same models.

OPS has failed to meet its burden of proving that Texas Gas performed leakage surveys on Class 3 pipelines using improper leak detection equipment at Greenville-Isola.

Item 11 of the Notice must be withdrawn because the Survey Reports, work orders and the Texas Gas-provided list of leak detection equipment do not establish that Texas Gas used improper leak detection equipment on unodorized transmission pipelines in Class 3 locations.\textsuperscript{147} OPS has not satisfied its burden of proof. The proposed compliance order and the proposed civil penalty must be withdrawn.

3. The Proposed Civil Penalty for Item 11 Must Be Withdrawn.

OPS proposes a $138,100 civil penalty for Item 11. OPS bears the burden of demonstrating a proposed civil penalty is appropriate for a pipeline safety violation.\textsuperscript{148} The Civil Penalty Calculation Worksheet and the Violation Report indicate that the amount of the proposed civil penalty is based on the allegation that Texas Gas performed 92 leakage surveys using improper

\textsuperscript{141} Attachment 9.
\textsuperscript{142} Attachment 10 at 2.
\textsuperscript{143} Attachment 9.
\textsuperscript{144} Violation Report, Exhibit K. For ease of reference, Texas Gas’s 2018 Survey Report for Greenville-Isola and Work Order No. 1415494 are attached as Attachment 15.
\textsuperscript{145} Attachment 15.
\textsuperscript{146} Notice at 7.
\textsuperscript{147} ExxonMobil, 2019 WL 3734516 at **4, 5 (ordering withdrawal of allegations where OPS failed to prove that Respondent engaged in conduct that would constitute a violation); EQT Corp., 2010 WL 2228558 at **6, 7 (finding that OPS did not present evidence or analysis proving that Respondent’s actions was inadequate under the regulation); Bridger Pipeline, 2009 WL 2336991 at **5, 6 (finding evidence introduced by PHMSA insufficient to establish a violation) Butte Pipeline, 2009 WL 3190794 at *1 (stating that a violation may be found only if the evidence supporting the allegation outweighs the evidence and reasoning presented by Respondent in its defense.”).
\textsuperscript{148} See e.g., Slusser, 210 F.3d at 787-88; see also Gimbel, 872 F.2d at 201; Premex, 785 F.2d at 1408-09; Bosma, 754 F.2d at 810.
leak detection equipment.\textsuperscript{149} The Violation Report states that “[i]nstances of violation are based on review of work orders and operator provided equipment list.”\textsuperscript{150} Texas Gas has demonstrated that information in the Violation Report does not establish either that the leak detection equipment identified in the Notice is inappropriate or that Texas Gas used this allegedly inappropriate equipment to perform leakage surveys on pipelines in Class 3 locations.

OPS has not met its burden of proving the alleged violations and has not demonstrated that the proposed remedy is appropriate or warranted.\textsuperscript{151} The proposed civil penalty for this item must be withdrawn.

**F. PHMSA Should Withdraw Item 13 and Eliminate or Substantially Reduce the Proposed Civil Penalty.**

Section 192.947 requires that an operator maintain for the useful life of a pipeline records demonstrating compliance with integrity management requirements.\textsuperscript{152} An operator must maintain documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.\textsuperscript{153}

Item 13 of the Notice alleges that Texas Gas “failed to maintain records that support decisions made or analysis performed on implemented P&M measures.” The Notice states that, for 2017, 2018, and 2019, Texas Gas did not document “the conclusions and decisions of the P&M measures implemented” and could not provide “documentation supporting the P&M measure chosen, such as the ‘What-if Analysis’ per IMP Chapter 8 Section 2.2.”\textsuperscript{154} OPS alleges, therefore, that Texas Gas “failed to support the justification in determining what P&M measures were implemented or how the measure chosen prevented or mitigated the risks identified for” 10 HCAs.

The Notice proposes a civil penalty of $195,700 based on 30 alleged violations: one violation for each year for each of the 10 HCAs.

Texas Gas contests the alleged violation. The P&M measures selected and implemented in each HCA are supported by Texas Gas’s Risk Analysis, a completed P&M Form, the Boardwalk Integrity Management Plan, and ASME/ANSI B31.8S. The Notice does not identify either a

\begin{itemize}
  \item \textsuperscript{149} Civil Penalty Work Sheet at 1; Violation Report at 56.
  \item \textsuperscript{150} Violation Report at 56.
  \item \textsuperscript{151} See e.g., Slusser, 210 F.3d at 787-88; see also Gimbel, 872 F.2d at 201; Premex, 785 F.2d at 1408-09; Bosma, 754 F.2d at 810.
  \item \textsuperscript{152} 49 C.F.R. § 192.947.
  \item \textsuperscript{153} Id. § 192.947(d).
  \item \textsuperscript{154} Notice at 8.
\end{itemize}
pipeline or public risk resulting from the alleged lack of documentation and does not identify any incremental safety benefit related to the documentation that OPS claims is missing.

Section 192.935 is the regulation that requires an operator to implement additional P&M measures “beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area.”\textsuperscript{155} Additional P&M measures are to be identified based on the threats identified on each segment and the risk assessment required under § 192.917.\textsuperscript{156}

Chapter 8 of the Boardwalk Integrity Management Plan implements § 192.935.\textsuperscript{157} Table 2-1 of Boardwalk’s Integrity Management Plan describes some of the P&M measures that Texas Gas may implement in HCAs based on the threat that is identified for each HCA and the factors that contribute to the magnitude of the consequences of failure.\textsuperscript{158} The Boardwalk Integrity Management Plan also describes activities involved in selecting and optimizing P&M measures.\textsuperscript{159}

In each year identified in the Notice, a Texas Gas subject matter expert completed a P&M Form for each HCA on the pipeline system, recording the identified threat and specifying the selected P&M measure(s) to mitigate the risks associated with each threat. Exhibit L of the Violation Report includes the P&M Forms that Texas Gas completed in 2018 for each of the 10 HCAs listed in the Notice.\textsuperscript{160} Texas Gas’s risk assessment shows that the threats of external corrosion and third-party damage presented a high level of risk to these HCAs.\textsuperscript{161} The P&M measures address those threats, and are consistent with the P&M measures identified in Table 2-1 of Boardwalk’s Integrity Management Plan and the Acceptable Threat Prevention and Repair Methods listed in Table 4 of ASME/ANSI B31.8S.\textsuperscript{162}

The chart below identifies for each HCA listed in the Notice, the threat(s) and the P&M measures that Texas Gas implemented in 2018 to mitigate the risks associated with each of those threats.

\textsuperscript{155} 49 C.F.R. § 192.935(a).
\textsuperscript{156} Id.
\textsuperscript{157} Violation Report, Exhibit L. For ease of reference, excerpts of Boardwalk’s Integrity Management Plan are attached hereto as Attachment 16.
\textsuperscript{158} Attachment 16 at 3-4, Table 2-1.
\textsuperscript{159} Attachment 16 at 10-12.
\textsuperscript{160} Violation Report, Exhibit L. For ease of reference, Texas Gas’s Preventative and Mitigative Measures Forms for 2018 are attached hereto as Attachment 17.
\textsuperscript{161} Violation Report, Exhibit L. For ease of reference, the results of Texas Gas’s risk analysis is attached hereto as Attachment 18.
<table>
<thead>
<tr>
<th>HCA</th>
<th>Identified Threat(s)</th>
<th>P&amp;M Measure(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003 – EUT 30 – 1TT – 84</td>
<td>External Corrosion</td>
<td>Close Interval Survey (CIS) On/Off Depolarization (One-time)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Cathodic Protection (CP) Monitoring/Maintain (Continuous)</td>
</tr>
<tr>
<td></td>
<td>Third Party/Mechanical Damage</td>
<td>Pipe-to-Soil test points within HCA (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Aerial Patrol: Frequency (26/yr) (Continuous)</td>
</tr>
<tr>
<td>2003 – MLS 26 – 2TT – 174</td>
<td>Third Party/Mechanical Damage</td>
<td>Aerial Patrol: Frequency (104/year) (Continuous)</td>
</tr>
<tr>
<td></td>
<td>Weather Outside Force</td>
<td>Aerial Patrol: Frequency (104/year) (Continuous)</td>
</tr>
<tr>
<td>2003 – MLS 26 – 2TT – 165</td>
<td>Third Party/Mechanical Damage</td>
<td>Aerial Patrol: Frequency (104/year) (Continuous)</td>
</tr>
<tr>
<td>2003 – MLS 26 – 2TT – 205-A</td>
<td>Third Party/Mechanical Damage</td>
<td>Aerial Patrol: Frequency (100/year) (Continuous)</td>
</tr>
<tr>
<td>2003 – SHC 20 – 1TT – 310</td>
<td>Third Party/Mechanical Damage</td>
<td>Aerial Patrol: Frequency (26/year) (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Foot Patrol: Frequency (4/year) (Continuous)</td>
</tr>
<tr>
<td>2003 – MLS 26 – 1TT – 105-2</td>
<td>External Corrosion</td>
<td>CIS On/Off Depolarization (One-time)</td>
</tr>
<tr>
<td></td>
<td>Welding Fabricated Related</td>
<td>CP Monitoring/Maintain (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pipe-to-Soil test points within HCA (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Other P&amp;M Activity: Reviewed section 2130 of O&amp;M Manual, discussed importance</td>
</tr>
<tr>
<td></td>
<td></td>
<td>of maintaining above equipment in these areas during annual maintenance</td>
</tr>
<tr>
<td></td>
<td></td>
<td>activities. (One-time)</td>
</tr>
<tr>
<td>2003 – MFB 20 - 1TT – 489-2</td>
<td>External Corrosion</td>
<td>CIS On/Off Depolarization (One-time)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CP Monitoring/Maintain (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pipe-to-Soil test points within HCA (Continuous)</td>
</tr>
<tr>
<td>2003 – MLS 26 – 1TT – 135-B</td>
<td>External Corrosion</td>
<td>CIS On/Off Depolarization (One-time)</td>
</tr>
<tr>
<td></td>
<td>Welding Fabrication Related</td>
<td>CP Monitoring/Maintain (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pipe-to-Soil test points within HCA (One-time)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>O&amp;M Procedures Training (One-time)</td>
</tr>
<tr>
<td>2003 – MLS 26 – 1TT – 131-2</td>
<td>External Corrosion</td>
<td>CIS On/Off Depolarization (One-time)</td>
</tr>
<tr>
<td></td>
<td>Welding Fabrication Related</td>
<td>CP Monitoring/Maintain (Continuous)</td>
</tr>
<tr>
<td></td>
<td>Incorrect Operations</td>
<td>Pipe-to-Soil test points within HCA (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>O&amp;M Procedures Training (One-time)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Other P&amp;M Activity: Participate in additional Integrity Management Training</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(Continuous)</td>
</tr>
</tbody>
</table>
Response of Texas Gas Transmission, LLC  
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April 13, 2022

<table>
<thead>
<tr>
<th>HCA</th>
<th>Identified Threat(s)</th>
<th>P&amp;M Measure(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012 – GUG 30 – 1TT – 623</td>
<td>External Corrosion</td>
<td>CIS On/Off Depolarization (One-time)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CP Monitoring/Maintain (Continuous)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pipe-to-Soil test points within HCA (Continuous)</td>
</tr>
<tr>
<td></td>
<td>Third Party/Mechanical Damage</td>
<td>CIS On/Off Depolarization (One-time)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Monitor Pipeline Excavations with Qualified Pipeline Personnel (Continuous)</td>
</tr>
</tbody>
</table>

This chart plainly shows that the P&M measures selected by Texas Gas are appropriate and tailored to mitigate the risks associated with threats identified for each HCA. For example, to mitigate the threat of external corrosion, Texas Gas performed a close interval survey, which is not required under Part 192. A close interval survey measures the potential (voltage) between the pipe and the surrounding soil to assess the performance and operation of the cathodic protection over the length of the pipeline. A close interval survey is a well-recognized means of assessing the adequacy of a pipeline’s cathodic protection and detecting the presence of external corrosion. This measure enhances Texas Gas’s ability to monitor, detect, and address external corrosion to mitigate the risk to pipeline integrity and to enhance public safety.

Conducting aerial patrols at intervals more frequent than required under Part 192 enables Texas Gas to effectively monitor activity on or near the right of way and to address activities that could lead to third-party or mechanical damage. The selection of foot patrols is also clearly tailored to mitigate the risk of third-party damage to the pipeline and to enhance public safety.

The Notice claims that for 2017, 2018, and 2019, Texas Gas “failed to maintain records that support decisions made or analysis performed on implemented P&M measures,” and that Texas Gas could not provide “documentation supporting the P&M measure chosen, such as the ‘What-if Analysis’ per IMP Chapter 8 Section 2.2.” ¹⁶³ Texas Gas’s P&M Forms and the information contained in them for each HCA, reflected in the above chart, belie that claim.

The Notice does not explain why Texas Gas’s P&M Forms are inadequate documentation to justify the selected P&M measure for each HCA. Each form specifies the identified threat and the measures selected to mitigate the risks associated with that threat. Each selected P&M measure directly mitigates the risks posed by each identified threat. The P&M measures are consistent with Texas Gas’s risk analyses, Table 2-1 of the Boardwalk Integrity Management Plan, and Table 4 of ASME/ANSI B31.8S. The Notice does not identify a safety risk created by the alleged lack of documentation or identify any incremental safety benefit created by having the allegedly missing documentation.

The “what-if” analysis identified in Boardwalk’s Integrity Management Plan is not mandatory. It is an example of the kind of documentation Texas Gas may choose to generate when selecting P&M measures. The P&M Forms created by Texas Gas for each HCA are more than enough to justify the measures selected to reduce the risks associated with the threats identified.

¹⁶³ Notice at 8.
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OPS has not satisfied its burden of proving a violation of § 192.947 and Item 13 must be withdrawn.

The proposed § 195,700 civil penalty also must be withdrawn. OPS bears the burden of demonstrating that a proposed civil penalty is appropriate for a pipeline safety violation.164 The proposed $195,700 civil penalty for allegedly failing to document a justification for P&M measures that clearly mitigate the risks of the identified threats to enhance pipeline and public safety is excessive, unwarranted and disproportionate to the alleged violation. The penalty should be eliminated or substantially reduced.

III. CONCLUSION

Based on the foregoing, Texas Gas requests that PHMSA withdraw Item 5, Item 6, Item 8, Item 11, and Item 13.

Respectfully submitted,

Tony G. Rizk, P. E.
Vice President, Technical Services

Attachments

164 See e.g., Slusser, 210 F.3d at 787-88; see also Gimbel, 872 F.2d at 201; Premex, 785 F.2d at 1408-09; Bosma, 754 F.2d at 810.