NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

<u>VIA ELECTRONIC MAIL TO:</u> **dwbritton@fngas.com**

March 1, 2023

Mr. Daniel Britton
General Manager
Interior Gas Utility
2525 Phillips Field Road
Fairbanks, AK 99709

CPF 5-2023-009-NOPV

Dear Mr. Britton:

From August 2 through 6, 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 your distribution system in Fairbanks, Alaska.

As a result of the inspection, it is alleged that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (CFR). The items inspected and the probable violations are:

1. § 192.16 Customer notification.

(a) . . . .
(b) Each operator shall notify each customer once in writing of the following information:
(1) The operator does not maintain the customer's buried piping.

Interior Gas Utility (IGU) supplied essential natural gas to Fairbanks and North Pole sites in Alaska at the time of inspection. IGU, a distribution operator, reported over sixteen hundred natural gas services in 2021. IGU did not have a customer notification process in place that satisfied the requirements of § 192.16. The operator did not provide any procedures, records, or documentation demonstrating it had notified customers that it did not maintain the customer's piping. There was no customer notification process in place, nor had any customers ever been notified as required by the regulation.

2. § 192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints*. Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints that are made according to the procedure to the following tests, as applicable:

IGU did not qualify its joining procedures as required in § 192.283. The Operator's Plastic Pipe Fusion Precautions SOP D-2220 stated, "The Plastic Pipe Fusion Precautions Procedure SOP 2220 is qualified thru the use of the manufactures qualified written procedures Chevron Phillips Chemical Company Performance Pipe procedures dated 2017." However, the Operator did not have a copy of a record demonstrating that testing and qualification of the joining procedures were completed by either the manufacturer or IGU. Similar statements were made in other joining procedures and no qualified joining records were produced during the inspection.

3. § 192.453 General.

The corrosion control procedures required by § 192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

IGU did not have any personnel who were qualified to conduct atmospheric corrosion inspections. IGU stated that its eWebOQ course, called *503COAT Protective Coating for Underground Buried Pipe,* provided adequate atmospheric corrosion inspection training. However, this course was specific to buried pipe, and atmospheric corrosion inspections are conducted on aboveground pipe. Additionally, this course was not included on the Web EQ list of courses distribution operators were required to take.

4. § 192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect and evaluate each pipeline or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

Pipeline type:	**Then the frequency of inspection is:**
(1) Onshore other than a Service Line	**At least once every 3 calendar years, but with intervals not exceeding 39 months.**

Pipeline type:	Then the frequency of inspection is:
(2) Onshore Service Line	**At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.**

IGU personnel did not inspect and evaluate IGU's aboveground piping for atmospheric corrosion at the intervals required. IGU provided a list of all meters as evidence of compliance with this requirement. However, the list was insufficient to demonstrate compliance because it did not include the following necessary information: whether an inspection occurred; the date of any inspection; who completed the inspection; or whether corrosion was looked for or found. IGU provided some records of meter inspections completed in 2019 that identified if paint was needed on a meter; however, there was no explicit corrosion inspection noted on the 2019 forms. Additionally, the 2019 forms encompassed inspections conducted on only 33 meters out of a system that had 1,206 meters in service in 2019.

5. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(a) *General*. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

IGU failed to follow its procedural manual for operations, maintenance, and emergencies (O&M) in two instances.

IGU failed to perform emergency response training as described in its Standard Operating Procedure (SOP) D-1105. IGU's emergency response training records documented the training that was completed but did not include company-wide training for "tabletop" emergency scenarios, as required by SOP D-1105.

Additionally, IGU did not follow its procedures to ensure that it's Odorator/Detex tools were calibrated for the sampling completed on the Fairbanks distribution system. SOP D-2125 Natural Gas Odorant and Odorator Procedures section: Periodic Tests described a requirement to periodically conduct tests to assure that Odorator/Detex tools were correctly calibrated. SOP D-2125 required annual calibration for the Odorameter/Detex equipment to be completed by the manufacturer. IGU did not provide any records demonstrating that either of these maintenance activities was conducted.

6. § 192.625 Odorization of gas.

(a) . . . .

> **(f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by -**
> **(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and**
> **(2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.**

IGU did not conduct periodic sampling to assure the proper concentration of odorant in the North Pole distribution system. IGU personnel stated to PHMSA inspectors that they had never conducted sampling of odorant concentration in the North Pole system. The North Pole system was commissioned in January 2021, and, at the time of the inspection in August 2021, IGU had never sampled the odorant levels in the system to ensure the gas was readily detectable.

7. § 192.739 Pressure limiting and regulating stations: Inspection and testing.

> **(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is -**
> **(1) . . . .**
> **(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and**

IGU did not complete the required inspection and testing at pressure limiting and regulator station Site 1 in 2020. IGU did not provide records demonstrating that pressure regulators at Site 1 were inspected in 2020.

8. § 192.743 Pressure limiting and regulating stations: Capacity of relief devices.

> **(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in § 192.739(b), the capacity must be consistent with the pressure limits of § 192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.**

IGU did not confirm the capacity of overpressure protection blowdown pressure relief valve PRV-600 by in-place testing or by review and calculations as required by § 192.743(a).

IGU provided records documenting pressure relief valve PRV-600 at Site 1 was lifted on 9/24/2018 and 9/19/2019, but neither of those records indicated that the relief valve capacity was adequate. IGU operators were aware that the relief device capacity was required to be reviewed or tested in place annually, but the records did not state that the Operator tested the device in place or that the capacity was reviewed and determined to be sufficient. IGU personnel stated that they typically pop the relief using nitrogen, which tests the set point of the relief but does not test capacity. IGU did not produce records demonstrating that the requirements of § 192.743 were met via the review and calculations option offered by § 192.743(b). A record for the 2020 annual inspection or capacity review of PRV-600 was not produced during the inspection. IGU previously received a warning for this alleged violation in CPF 5-2020-0003W.

9. § 192.747 Valve maintenance: Distribution systems.

(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

IGU did not conduct any distribution valve inspections in 2019. There were some 2020 records demonstrating that some distribution valves were inspected; however, IGU's distribution valve inspections focused on checking the conditions of the areas around valves and ensuring the valves were accessible but did not include checking the functionality and condition of the valves. For example, a record called Valve Inspection Form 2020 shows N/A for Valve Exercised column for each distribution valve listed as having been inspected in the year 2020.

10. § 192.756 Joining plastic pipe by heat fusion; equipment maintenance and calibration.

Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

IGU did not inspect and maintain their joining equipment as required by § 192.756. IGU failed to provide any records to demonstrate that the required inspections had been performed and admitted their joining equipment was not being maintained per manufacturer's recommended practices.

11. § 192.1007 What are the required elements of an integrity management plan?

(a) . . . .
(c) *Evaluate and rank risk.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

IGU did not have a written procedure that described the integrity management risk ranking and evaluation process, and the IGU Engineering Department personnel who manage and administer IGU's Distribution Integrity Management Plan (DIMP) were not familiar with the Simple, Handy, Risk-based Integrity Management Program (SHRIMP) software and were unable to explain the risk reranking completed by IGU.

IGU's DIMP began with a document that was titled Appendix F, pages 6&7 of DIMP Part 1, which provided a procedural overview of the DIMP. Appendix F explained a method for evaluating and ranking risks by creating Evaluate and Rank Risk tables to be compiled with historical data and used as an outlining tool to evaluate and rank the risks associated with the distribution system. This risk ranking process described in the DIMP was not used in the analysis. Rather, IGU's risk ranking was completed via a software program called SHRIMP (beginning page 13/40 of DIMP Part 1). IGU reordered the risk ranking provided by the SHRIMP program but failed to document the reason for the reordering of the risk ranking or document adequate explanations for why the risk ranking was changed.

12. § 192.1007 What are the required elements of an integrity management plan?

> **(a) . . . .**
> **(d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).**

IGU did not implement measures designed to reduce the risks from failure of its gas distribution pipelines.

The DIMP did not require additional actions to prevent or mitigate its number 2 risk, identified as: "Equipment Malfunctions Due to Failing Regulators/relief Valves on the Failing Equipment". IGU's DIMP stated additional actions associated with the mitigation of this risk were not required because "FNG's[1] SOPs adequately provide for the inspection and testing of equipment, including regulators and relief valves" (page 35/40 of DIMP Part 1). However, no documentation was provided that demonstrated customer regulators and meters were inspected on a regular basis.

Additionally, the risk ranked number 5, "Material, Weld or Joint Due to Workmanship Defects on the Specific_02 section", had an additional action selected of accelerating leakage surveys to be conducted annually for this section of the system (page 38/40 of DIMP Part 1). When questioned about this, IGU personnel weren't aware of the Specific_02 section and what part of the system it represented. No segments of IGU's system were on an accelerated leakage survey schedule beyond what is required in the code.

Finally, the threat ranked as risk number 6, "Other Outside Forces" stated that IGU had to perform patrols to ensure proper meter maintenance periodically (page 39/40 of DIMP Part 1).

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1 The Operator Interior Gas Utility (IGU) formerly operated the Fairbanks distribution system under operator name Fairbanks Natural Gas (FNG).

However, IGU personnel were unsure whether this was being done and was unable to produce any records documenting these actions had been taken.

Proposed Civil Penalty
Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed $257,664 per violation per day the violation persists, up to a maximum of $2,576,627 for a related series of violations. For violation occurring on or after March 21, 2022 and before January 6, 2023, the maximum penalty may not 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 $107,400 as follows:

Item number	PENALTY
4	$ 20,400
6	$ 50,200
7	$ 36,800

Warning Items
With respect to items 2, 5, 10 and 12, we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct these items. Failure to do so may result in additional enforcement action.

Proposed Compliance Order
With respect to items 1, 3, 6, 8, 9, and 11 pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Interior Gas Utility. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

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 you submit 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 your receipt of this Notice, you have 30 days to respond as described in the enclosed *Response Options*. 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 receipt of this Notice. The Region Director may extend the period for responding upon a written request timely submitted demonstrating good cause for an extension.

In your correspondence on this matter, please refer to **CPF 5-2023-009-NOPV,** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Dustin Hubbard
Director, Western Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Enforcement Proceedings

cc: PHP-60 Compliance Registry
PHP-500 G. St. Pierre (#21-217219)
Mark Rockwell, Interior Gas Utility (via email)
Brendan Kern, Engineer, Interior Gas Utility (via email)

<u>PROPOSED COMPLIANCE ORDER</u>

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Interior Gas Utility (IGU) a Compliance Order incorporating the following remedial requirements to ensure the compliance of Interior Gas Utility with the pipeline safety regulations:

A. In regard to Item Number 1 of the Notice pertaining to IGU not having a customer notification process in place that satisfied the requirements of § 192.16, IGU must update their procedures to include a customer notification process that satisfies the requirement of § 192.16, notify all their customers of the information required by § 192.16, and submit to PHMSA documentation that customers were given notice within **180** days of receipt of the Final Order.

B. In regard to Item Number 3 of the Notice pertaining to qualified personnel conducting atmospheric corrosion inspections, IGU must properly train and qualify personnel to conduct atmospheric corrosion inspections and provide training records to the Director within **180** days of receipt of the Final Order.

C. In regard to Item Number 6 of the Notice pertaining to odorant sampling, IGU must complete sampling the North Pole distribution system with properly calibrated odorant sampling equipment. Please provide calibration and sampling records to the Director within **180** days of receipt of the Final Order.

D. In regard to Item Number 8 of the Notice pertaining to capacity of overpressure protection blowdown pressure relief valve PRV-600, IGU must confirm the capacity PRV-600 by in-place testing or by review and calculations as required by § 192.743(a). Please provide evidence of completion of this task to the Director within 180 days of receipt of the Final Order.

E In regard to Item Number 9 of the Notice pertaining to required distribution valve inspections including functionality checks, IGU must inspect and exercise every distribution valve, document the inspections appropriately and submit records to the Director within 270 days of receipt of the Final Order.

F. In regard to Item Number 11 of the Notice pertaining to the Distribution Integrity Management Plan (DIMP) risk ranking and evaluation process, IGU must submit a new risk ranking and evaluation that is completed as described in the operator's procedures, with a risk ranking that is adequately defended within **270** days of receipt of the Final Order.

G. It is requested (not mandated) that Interior Gas Utility maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Dustin Hubbard, Director, Western Region, Pipeline and Hazardous Materials Safety Administration. It is requested that these costs be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.