2022 SAFETY OF GAS TRANSMISSION FINAL RULE FAQs:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing a regulatory guidance document in the form of frequently asked questions (FAQs). These FAQs clarify certain regulatory amendments adopted in PHMSA's recently issued final rule titled "Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" (87 FR 52224 (Aug. 24, 2022), as amended by 88 FR 24708 (Apr. 24, 2023) (collectively, the "2022 Gas Transmission Final Rule"). PHMSA developed these initial FAQs to respond to questions raised by stakeholders on the 2022 Gas Transmission Final Rule, and PHMSA expects, as part of its ordinary efforts, to periodically add additional FAQs addressing other provisions of the 2022 Gas Transmission Final Rule to help aid in consistent implementation and application of the regulatory amendments.

PHMSA provides FAQs to help the public understand how to comply with the regulations. Like all PHMSA guidance, FAQs are not substantive rules, do not have the force or effect of law, and do not create new legal obligations. An operator who is able to demonstrate that it is acting in accordance with FAQs, however, is likely to be able to demonstrate compliance with the relevant regulations. If a pipeline operator chooses not to follow FAQs, the operator must be able to demonstrate the operator's conduct complies with the regulations.

1. **When evaluating a pipeline to determine if it is a "transmission line," how should an operator consider the phrase "a connected series of pipelines" in § 192.3?**

The definition of a "transmission line" is found in 49 CFR 192.3. A pipeline is a "transmission line" if the pipeline or connected series of pipelines (other than a gathering line) transports gas from a gathering pipeline or storage facility and brings it to a distribution center, storage facility, or a large volume customer (not downstream of a distribution center). It may also be a transmission line if the MAOP is 20% or more of SMYS, it transports gas within a storage field, or an operator may also voluntarily elect to designate a pipeline as a transmission line for regulatory purposes.

The phrase a "connected series of pipelines" in the § 192.3 definition does not affect the designation of each individual pipeline within that connected series. Each pipeline, even those connected in series, is determined to be transmission, or not, based on its individual pipeline characteristics (or on designation by the operator).

2. May an "in-line inspection" be performed using free-swimming tools?

Yes, the instrumented in-line inspection (ILI) tools in § 192.3 include inspection performed using "free-swimming" ILI tools (i.e., propelled by the gas flow), as well as tethered or self-propelled ILI tools (which are not "free-swimming" ILI tools). 87 FR at 52256. An ILI is an inspection of a pipeline from its interior, and the tools used to perform an ILI may also be called "intelligent" or "smart pigging" tools. § 192.3.

The 2022 Gas Transmission Final Rule did not modify the definition of a moderate consequence area in §§192.710(a)(2) and 192.624(a)(2)(iii) as being a pipeline segment that can be inspected using an ILI tool that is free-swimming and does not require modifications to the pipeline segment. *See* 87 FR at 52256.

3. What data do I consider when identifying and evaluating threats under § 192.917? What data is "pertinent"?

As part of their integrity management plans, operators are responsible for developing an integrity program to identify potential threats to each covered pipeline segment in an HCA. The potential threats to consider include, but are not limited to, the threats listed in ASME/ANSI

B31.8S. § 192.917(a). Threat identification includes gathering all existing data (i.e., pipeline attributes and operational and environmental parameters) on the covered pipeline segment that could be relevant, and then integrating that pertinent data into an operator's integrity management program and procedures. § 192.917(b).

In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. "The types of data to support a risk assessment will vary depending on the threat being assessed. Information on the operation, maintenance, patrolling, design, operating history, and specific failures and concerns that are unique to each system and segment will be needed." *See* ASME/ANSI B31.8S, section 2.3.2. ASME/ANSI B31.8S, section 4, and § 192.917(b)(1) identify certain data which is pertinent.

Section 192.917(b)(1) lists information that will be pertinent. In determining which data is pertinent to integrate in threat identification and risk assessment for a specific covered pipeline segment, an operator must follow the requirements in ASME/ANSI B31.8S, section 4.[1]

The pertinence of individual data depends on the threat identification on a specific pipeline segment, and not all data across a pipeline will be pertinent for a given pipeline segment. "By analyzing all of the pertinent information, the operator can determine where the risks of an incident are the greatest, and make prudent decisions to assess and reduce those risks." See introduction to ASME/ANSI B31.8S ("Integrity Management Principles").

[1] ASME, B31.8S-2004, "Managing System Integrity of Gas Pipelines," sec. 4 (2005) ("ASME/ANSI, B31.8S").

4. **Section 192.465 references two terms for different sources of external cathodic causes to investigate and mitigate—non-systemic and systemic causes—what's the difference?**

Section 192.465 provides for annual testing of external corrosion controls, with investigative and mitigative steps for an operator to take if it detects low cathodic protection levels along the pipeline. Section 192.465(f) sets out mitigative steps to respond to the two different sources of low cathodic protection levels: "systemic" or "non-systemic" causes. The difference is based on the extent of the area impacted.

Systemic causes are problems that have an effect on a portion of the pipeline and could lead to corrosion at multiple points along the pipeline. For example, insufficient cathodic protection level readings at a cathodic protection test site could affect a sufficient length of the pipeline due to a common (systemic) cause. For a systemic cause, the operator must perform close interval surveys in both directions from the test station that is producing the low reading. An operator must remediate areas with insufficient cathodic protection and confirm that adequate cathodic protection has been restored. § 192.465(f)(2).

Non-systemic causes are isolated, location-specific causes of low cathodic protection levels that may be readily identifiable at the point of the pipeline equipment. For example, a blown fuse in a cathodic protection rectifier that is corrected upon replacing the fuse would be a non-systemic cause as it is limited to the one fuse. When that fuse is replaced at that location, and the rectifier settings are confirmed, the remediation is complete under § 192.465(f)(1) as the location-specific cause has been remedied. Examples of other non-systemic causes could be loss of power to the rectifier, broken test wire, or replacement of rectifier. For such non-systemic causes, an operator need not conduct close interval surveys in both directions from the rectifier, unless the operator has information that it feels requires confirmation using a close interval survey. Nonetheless, operators should be diligent to investigate problems that appear to be location-specific to determine if it is indicative of a systemic cause. For example, a blown fuse on a rectifier could be evidence of a defect with the design or manufacture of the fuse itself that could affect every rectifier where that type/brand of fuse is used.

5. **What remediation schedule should be implemented for a monitored condition under § 192.933(d)(3) with indications it "is expected to grow to dimensions" prior to the next scheduled assessment? How do I judge whether a monitored condition is expected to grow in dimensions?**

Ordinarily, monitored conditions under § 192.933(d)(3) do not require examination and evaluation until the next scheduled assessment (i.e., seven years). Operators must, however, in the evaluation assess the growth rate of time-dependent anomalies resulting from internal corrosion, external corrosion, denting, cracking, or a combination of these defects to ensure that the anomaly will not attain critical dimensions (i.e., those of a condition under § 192.933(d)(2)) prior to the scheduled repair or next assessment. If the anomaly is expected to attain the dimensions or have a predicted failure pressure (with a safety factor) of a § 192.933(d)(2) scheduled condition before the next scheduled assessment, an operator must make the repair before it reaches that point (i.e., before it is expected to "grow" to that dimension). § 192.933(d)(3). Otherwise, the condition can remain monitored until the next scheduled assessment.

The use of ASME/ANSI B31.8S, section 7.2.4 Limitations to Response Times for Prescriptive-Based Program is an acceptable method for evaluating anomaly growth to determine whether an anomaly is expected to grow in dimensions prior to the next scheduled assessment.

6. The monitored conditions at §§ 192.714(d)(3) and 192.933(d)(3) include that "critical strain levels are not exceeded." How should I treat a condition if the critical strain levels of my anomaly are exceeded?

"An operator must remediate [all] conditions according to a schedule that prioritizes the conditions for evaluation and remediation." §§ 192.714(c), 192.933(c). Sections 192.714(d) and 192.933(d) provide a schedule for immediate, scheduled (1 or 2 year), and monitored conditions, where monitored conditions (§§ 192.714(d)(3) and 192.933(d)(3)) are the least severe and should be monitored by operators to ensure no further degradation occurs.

Several pipeline safety threats provide for evaluation of the anomaly using an engineering critical assessment (ECA). When the ECA results demonstrate that critical strain levels are not exceeded, the anomaly is identified as a monitored condition, *see* §§ 192.714(d)(3)(i)-(iv), 192.933(d)(3)(i)-(iv), while the same threat must be remediated as a scheduled or immediate condition, as appropriate, where the ECA shows that critical strain levels are exceeded for these conditions, *see* §§ 192.714(d)(2), 192.933(d)(2). *See also* 88 FR at 24709.