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PIPELINE SAFETY *ALERT*

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PHMSA Publishes Final Rule Introducing New Requirements for Gas Transmission Pipeline Operators

On August 24, 2022, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published a new final rule for onshore gas transmission pipelines (the Rule). The Rule marks the completion of a three-phase rulemaking process, commonly referred to as the Gas Mega Rule, that began more than a decade ago. While this part of the Gas Mega Rule is commonly known as the "Repair Rule," there are numerous other safety provisions that are included in the new regulation that should not be overlooked. The Rule amends or adds various provisions in 49 C.F.R. Part 192 and will become effective on May 24, 2023. In the Rule, PHMSA added, clarified, or modified the following sections of the natural gas pipeline safety regulations:

- definitions in section 192.3;
- the management of change process;
- corrosion control requirements;
- inspections of pipelines following extreme weather events;
- integrity management provisions;
- integrity management assessment requirements;
- revised repair criteria in high consequence areas; and
- new repair criteria for non-high consequence areas.

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Definitions and Standards Incorporated by Reference

PHMSA added new definitions referenced in the new regulations, including close interval survey, distribution center, dry gas or dry natural gas, hard spot, in-line inspection (ILI), in-line inspection tool or instrumented internal inspection device, and wrinkle bend. Furthermore, the definition of transmission pipelines was revised to include a "connected series" of pipelines to clarify that transmission pipeline can be downstream of other transmission pipelines, and to allow operators to voluntarily designate their pipelines as transmission lines.

The rule also incorporates by reference two NACE standards, NACE SP0204-2008 and NACE SP0206-2006, for stress corrosion cracking direct assessments and internal corrosion direct assessments. These new IBR standards support the new corrosion amendments to the Rule.

Management of Change

PHMSA extended management of change requirements to onshore gas transmission pipelines not currently subject to integrity management requirements. The Agency also amended the existing management of change process in § 192.911(k) to codify specific attributes listed in ASME/ANSI B31.8S, section 11.

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Operators of all onshore gas transmission pipelines must now evaluate and mitigate any significant changes that pose a risk to safety or the environment through a management of change process.

The process must include the reasons for the change, the authority for approving changes, an analysis of the implications, the acquisition of required work permits, and evidence documenting communication of the change to affected parties, time limitations, and the qualification of staff. Although the Gas Pipeline Advisory Committee had recommended a two-year phased in compliance period, the Agency mandated an 18-month time frame to incorporate the management of change process for pipelines in non-HCAs. For pipeline segments not covered by Subpart O, operators must implement this management of change process by February 26, 2024. Operators may seek a technically justified extension of this deadline of up to one year through the section 192.18 notification process. PHMSA specifically noted that these changes do not apply retroactively and do not cover gathering or distribution pipelines.

Corrosion Control and Related Construction Requirements

The Rule amends numerous corrosion control requirements for onshore gas transmission pipelines, addressing the monitoring and remediation, if needed, of both external and internal corrosion. The Agency issued new requirements to conduct pipe coating assessments soon after construction, determine protective coating strength, survey for interference currents, and monitor gas streams for internal corrosivity. In conjunction with the enhanced corrosion monitoring for internal and external corrosion, PHMSA established new corrosion control remediation criteria and timelines to correct deficiencies found. PHMSA acknowledged that these new construction and corrosion control requirements do not apply to gathering or distribution pipelines.

Pipe Coating

PHMSA added new construction requirements concerning the installation of pipe in a ditch (section 192.319). If a construction project involves 1,000 feet[1] or more of continuous backfill length along the pipeline, the operator must promptly (but not later than six months after placing the pipeline in service) perform an above-ground indirect assessment to identify any coating damage using direct current voltage gradient, alternating current voltage gradient, or other technology. If an operator chooses to use alternative technology, it must notify PHMSA at least 90 days in advance and seek a letter of no objection through the process described in section 192.18. An operator must repair any severe coating damage within six months after the pipeline is put in service (or as soon as practicable after obtaining the necessary permits). The operator must retain records documenting the coating assessment findings and repairs for the life of the pipe.

PHMSA made similar modifications to section 192.461 requiring an onshore gas transmission operator to conduct an above-ground indirect assessment if the backfill length of a repair or a replacement project is 1,000 feet or more. The operator would need to conduct the assessment promptly but no later than six months after the backfill. The operator may also notify PHMSA of its intent to use alternative technology by following the process in section 192.18. The operator must develop a remedial action plan within six months of completing the assessment and repair any severe coating damage within six months of the assessment or as soon as practical upon obtaining the necessary permits. The operator must retain records of the assessment findings and remedial actions for the life of the pipe.

[1]PHMSA stated in the preamble that §§ 192.319 and 192.461 apply to segments "greater than 1,000 feet in length" but used "1,000 feet or more" in the rule text.

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Interference Surveys and Remediation

PHMSA amended section 192.473 to require interference surveys for pipelines subject to stray currents. Currently, an operator with a pipeline subject to stray currents must have a program to minimize the detrimental effect of these currents. An operator with such a pipeline will now have to conduct an interference survey to quantitatively determine the presence and level of interference currents. PHMSA provides in the Rule that an interference survey must be conducted when the monitoring indicates a significant increase in stray current or when new potential stray current sources are introduced. An operator must analyze the results of the survey to determine the cause of the interference and develop a remedial action plan to correct any deficiency if the current is greater than or equal to 100 amps per meter squared or if it impedes the safe operation of the pipeline or if it may cause a condition that would adversely impact the environment or the public. The operator must complete the remediation promptly but no later than the earlier of (1) 15 months of completing the survey or (2) as soon as practicable but not to exceed six months after obtaining the necessary permits.

Cathodic Protection and Remediation

Although operators already have a general obligation under § 192.465(d) to promptly remediate any corrosion control deficiencies discovered during cathodic protection (CP) monitoring, PHMSA has now added a requirement for onshore gas transmission operators to develop a remedial action plan for both localized/non-systemic and widespread/systemic corrosion control deficiencies found by the CP monitoring within six months of discovery. The operator must complete the remedial action promptly but no later than the earlier of (1) the next inspection or test interval; (2) within one year, not to exceed 15 months, or (3) as soon as practicable, not to exceed six months after obtaining any necessary permits.

For areas where an annual test station reading indicates inadequate cathodic protection below the required levels in Appendix D, operators must investigate the geographical extent and causes of the low CP levels to determine whether there is systemic/widespread or non-systemic/localized areas of deficient CP. Operators must conduct close interval surveys (CIS) to delineate the pipe segments requiring CP remediation. The CIS must be conducted with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must promptly remediate pipe segments with insufficient cathodic protection, and, following the remediation, confirm the restoration of sufficient cathodic protection.

Internal Corrosion Monitoring and Mitigation

While section 192.477 includes requirements to monitor for internal corrosion if corrosive gas is transported, PHMSA is now adding requirements to continually monitor the gas stream for corrosive constituents. The Rule requires operators to develop a monitoring and mitigation plan for pipelines that transport gas with corrosive constituents. The Rule includes specific content requirements for the plan including an obligation to evaluate the gas monitoring data and review and adjust the plan, if necessary, once each calendar year (not to exceed 15 months).

Remedial Measures

Finally, the Rule amends § 192.485, requiring operators to determine whether remedial measures for general or localized corrosion pitting are necessary by calculating remaining pipe wall thickness using the analysis of predicted failure pressure requirements in § 192.712. While the addition of §192.712 was part of the first phase of the Mega Rule, which focused on MAOP Reconfirmation, this revision to § 192.485 clarifies that determination of remaining strength of pipe in corroded areas must be completed and documented in accordance with § 192.712 for all transmission pipelines, not just those lines that are reconfirming their MAOP.

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PHMSA expanded section 192.712 to include dents and other mechanical damage. The expanded analytical requirements will include evaluation of dent and other mechanical damage that could cause a stress riser, exceed the critical strain threshold, or otherwise degrade the integrity of the pipeline.

Inspections and Remedial Action Following Extreme Weather Events

Similar to the requirements for hazardous liquid pipeline operators, PHMSA has now expanded continuing surveillance requirements for an operator to perform an initial inspection following extreme weather events. Numerous examples of extreme weather events are listed and include geohazards such as earthquakes, river channel migration, and landslides. The operator must conduct the inspection 72 hours after it reasonably determines that the affected area can be safely accessed by personnel and equipment and the equipment and personnel are available. The Rule also requires operators to take prompt remedial action discovered during the inspection.

Integrity Management

A significant portion of the Rule focuses on the integrity management (IM) program requirements in 49 C.F.R. 192 Subpart O. The Rule prescribes new or amended requirements for identifying and analyzing threats, performing direct assessments, repairing pipelines, and implementing preventive and mitigative measures (P&MM).

Threat Identification and Data Integration

PHMSA has added certain pipeline attributes from ASME/ANSI B31.8S directly into the pipeline safety regulations. Current IM regulations require operators to conduct a risk assessment using the identified threats to determine what additional P&MM are needed to ensure the safe operation of the pipeline. Operators must begin to integrate all pertinent data elements starting on May 24, 2023, with all available attributes integrated by February 26, 2024. An operator may request an extension of up to one year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18.

Internal Corrosion Direct Assessment and Stress Corrosion Cracking Direct Assessment

The rule addresses direct assessments by incorporating NACE SP0204-2008 and NACE SP0206-2006 by reference. These standards concern stress corrosion cracking direct assessment and internal corrosion direct assessment, respectively.

Repair Criteria

Finally, the Rule provides a robust overhaul of current repair criteria regulations. The Rule applies integrity-related repair criteria to pipelines not subject to the integrity management requirements in Subpart O. Repair criteria for immediate conditions, which include certain crack, dent, and corrosion anomalies, are identical to those in Subpart O (as revised by the final rule and summarized in the chart below). Operators of non-Subpart O pipelines have two years to repair "one-year conditions," which vary slightly from those in Subpart O, and must monitor certain conditions. The Rule requires operators to use these repair criteria when making permanent repairs on transmission lines located outside of HCAs.

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The chart below provides a high-level summary of the new requirements:

Immediate Repair Conditions	One-year Conditions	Monitored Conditions
Metal loss anomaly with failure pressure ≤ 1.1 x MAOP	*Smooth dent in upper 2/3 of the pipe with depth > 6% of OD	**Dent in bottom 1/3 of pipe with depth > 6% of OD
*Dent in upper 2/3 of the pipe with metal loss, cracking, or a stress riser	*Dent with depth > 2% of OD that affects girth or long seam weld	**Dent in upper 2/3 of the pipe with depth > 6% of OD
Metal loss > 80% of nominal wall	*Dent in lower 1/3 of the pipe with metal loss, cracking, or a stress riser	**Dent with depth > 2% that affects girth or long seam weld
Metal loss preferentially affecting certain long seams and failure pressure < 1.25 x MAOP	Metal loss with failure pressure < 1.39 x MAOP	**Dent with metal loss, cracking, or a stress riser
Crack plus any metal loss > 50% wall thickness	Metal loss located at a crossing with another pipeline and certain failure pressure based on class location	Metal loss preferentially affecting certain long seams and certain failure pressure based on class location
Crack plus any metal loss > inspection tool's max measurable depth	Metal loss preferentially affecting certain long seams and certain failure pressure based on class location	Crack with certain failure pressure based on class location
Crack with failure pressure < 1.25 x MAOP	Crack with certain failure pressure based on class location	
Any anomaly that requires immediate action		

*Exception if an engineering analysis performed in accordance with § 192.712(c) demonstrates that critical strain levels are not exceeded
**An engineering analysis performed in accordance with § 192.712(c) must demonstrate that critical strain levels are not exceeded.

Other Considerations

In accordance with 49 C.F.R. § 190.335, any interested party may seek reconsideration of the rule by filing a petition with PHMSA by September 23, 2022. Petitions for judicial review must be filed no later than 89 days after the regulation is prescribed.

For a more detailed assessment or to discuss the implications of the final rule, please contact Keith Coyle at 202.853.3460 or KCoyle@babstcalland.com, Chris Hoidal at 202-853-3455 or CHoidal@babstcalland.com, or Brianne Kurdock at 202.853.3462 or BKurdock@babstcalland.com.

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Led by three former Pipeline and Hazardous Materials Safety Administration (PHMSA) attorneys, our Pipeline and Hazardous Materials Safety practice group counsels pipeline and midstream companies, gas utilities, terminal operators, investors, trade associations, and other stakeholders, throughout the United States. James Curry, Keith Coyle and Brianne Kurdock together have more than 25 years of experience with a multitude of pipeline safety issues. They partner with client engineering and legal personnel to address day-to-day compliance questions and develop business and regulatory strategies.