BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Mandatory Regulatory Reviews to Unleash American Energy and Improve Government Efficiency	Docket No. PHMSA-2025-0050

COMMENTS IN RESPONSE TO "MANDATORY REGULATORY REVIEWS TO UNLEASH AMERICAN ENERGY AND IMPROVE GOVERNMENT EFFICIENCY" ADVANCE NOTICE OF PROPOSED RULEMAKING

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I. Introduction

The American Petroleum Institute (API), Liquid Energy Pipeline Association (LEPA), and GPA Midstream Association (GPA), collectively, the Associations, submit this comment in response to the Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency)'s Mandatory Regulatory Reviews to Unleash American Energy and Improve Government Efficiency Advance Notice of Proposed Rulemaking (ANPRM).[1]

API represents all segments of America's natural gas and oil industry, which supports more than 11 million U.S. jobs and is backed by a growing grassroots movement of millions of Americans. Our approximately 600 members produce, process and distribute the majority of the nation's energy, and participate in API Energy Excellence®, which is accelerating environmental and safety progress by fostering new technologies and transparent reporting. API was formed in 1919 as a standards-setting organization and has developed more than 800 standards to enhance operational and environmental safety, efficiency and sustainability.

LEPA promotes responsible policies, safety excellence, and public support for liquids pipelines. LEPA represents pipelines transporting 97 percent of all hazardous liquids barrel miles reported to the Federal Energy Regulatory Commission. LEPA's diverse membership includes large and small pipelines carrying crude oil, refined petroleum products, natural gas liquids, and other liquids.

GPA has served the U.S. energy industry since 1921. GPA is composed of over 50 corporate members that directly employ over 57,000 employees that are engaged in the gathering, transportation, processing, treating, storage and marketing of natural gas, natural gas liquids (NGLs), crude oil, and refined products, commonly referred to in the industry as "midstream activities." In 2023, GPA members operated over 506,000 miles of pipelines, gathered over 91 Bcf/d of natural gas, and produced over 5.3 million barrels/day of NGLs from over 365 natural gas processing facilities.

The Associations support PHMSA's efforts to review its regulations to eliminate any undue burdens on the identification, development, and use of domestic energy resources and to improve government efficiencies.

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[1] Pipeline Safety: Mandatory Regulatory Reviews to Unleash American Energy and Improve Government Efficiency, 90 Fed. Reg. 23,660 (June 4, 2025).

II. Executive Summary

The Associations appreciate the opportunity to review the pipeline safety regulations, interpretations, and enforcement actions and identify areas of clarification or improvement.[2] The Associations have provided their collective feedback in this document. To aid PHMSA in its review, the Associations have indexed their top priorities into three tiers:

Tier 1

- **Reform Cathodic Protection Requirements for Breakout Tanks**
- **Limit State Damage Prevention Exemptions**
- **Remove Prescriptive Threshold for Rupture Designation**

Tier 2

- **Reform Reporting of Initial Estimate of Release Volume**
- **Allow Check Valves for Rupture Mitigation**
- **Include Dredging or Marine Excavation in "Excavation Activities" Damage Prevention Definition**

Tier 3

- **Require State Enforcement of Damage Prevention Violations**
- **Right-of-Way Maintenance Flexibility for Conservation**
- **Flexibility on Point-to-Point Verification**

The Associations have also included regulatory priorities from other dockets and cross-referenced those topics accordingly. These priorities include:

- **Fulfill Congressional Mandate for Rulemaking on Idled Pipe Operating Status**
- **Reform Special Permit Process**
- **Targeted Update of CO2 Pipelines Safety Requirements**

Finally, the Associations have provided other recommendations responsive to PHMSA's questions in the ANPRM. The Associations seek meaningful changes to Part 190, corrosion control, pressure testing, operations and maintenance, gathering, reporting, and emergency response requirements.

III. Comments

A. Tier 1 Priorities

[2] The Associations also request that PHMSA ensure the states are supporting the same inspection and enforcement priorities as PHMSA to avoid inconsistencies. Program fees and grants should be tied to performance under the directives.

The Associations place the highest priority in PHMSA undertaking the following regulatory reforms:

1. Reform Cathodic Protection Requirements for Breakout Tanks[3]

The Associations request that PHMSA modify sections 195.563 and 195.565 to document that cathodic protection (CP) is not required for double bottom breakout tanks and other breakout tanks that are isolated from contact with soil by concrete, asphalt, or other non-conductive materials. Under 49 CFR §195.563, CP is mandated only for buried or submerged regulated assets, which are defined in § 195.553 as those "covered or in contact with soil." This definition explicitly excludes above-ground breakout tanks and associated piping that are isolated from contact with soil. This interpretation is reinforced by PHMSA Interpretation PI-20-0014, issued January 10, 2022, which addressed breakout tanks constructed on concrete pads. PHMSA concluded that only breakout tanks in contact with soil are subject to CP requirements under §195.563(a).

From a technical standpoint, API RP 651 Section 5.1.4 outlines the limitations of cathodic protection in environments where electrical current cannot flow effectively between anodes and the tank bottom. Factors that inhibit current flow include:

- Concrete, asphalt, or oiled sand tank pads
- Non-conductive liners between the tank bottom and anodes

In double-bottom tank systems, the interstitial space is often filled with non-conductive materials, and the release barrier or liner blocks the electrical path necessary for CP to function due to electrical isolation and poor current distribution. As noted in API RP 651 Section 7.2.5, CP is ineffective unless anodes are placed within the interstitial space—a practice that is rarely implemented due to design and maintenance constraints. Double-bottom tanks utilize sand or other materials between the primary and secondary bottoms that are designed to prevent moisture ingress, thereby significantly reducing the risk of corrosion. When these tanks are correctly constructed and maintained, the high resistivity of the fill materials and the absence of corrosive elements, such as chlorides, in the interstitial space make cathodic protection not only unnecessary but potentially problematic. Attempting to install cathodic protection in such configurations can introduce new risks, such as water intrusion through access points.

Operators rely on robust design, moisture control, leak detection, and regular inspections in accordance with API 653 standards. It is important to recognize that tank bottoms are routinely monitored through corrosion growth assessments as part of API 653 inspections. API 653, which governs the inspection, repair, alteration, and reconstruction of aboveground storage tanks, requires operators to evaluate the rate of corrosion over time and determine the remaining life of the tank bottom. This process includes ultrasonic thickness measurements and other non-destructive testing methods that provide direct, quantifiable data on the condition of the tank bottom. These assessments are conducted at regular intervals and are

[3] This section is in response to ANPRM Question #B.6.

tailored to the specific design and operating conditions of each tank, ensuring that corrosion risks are effectively managed even in areas not subject to cathodic protection or atmospheric exposure. Therefore, the use of API 653 corrosion growth assessments provides a robust and proactive approach to integrity management for tank bottoms that are neither buried nor exposed to the atmosphere. This approach not only aligns with PHMSA guidance but also ensures long-term integrity and safety without the complications and costs associated with unnecessary CP systems.

The Associations request that PHMSA modify sections 195.563 and 195.565 accordingly:

> **§ 195.563 Which pipelines must have cathodic protection?**
>
> (c) All other buried or submerged pipelines that have an effective external coating must have cathodic protection. ~~Except as provided by paragraph (d) of this section, this requirement does not apply to buried breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003.~~
>
> (d) Bare pipelines, breakout tank areas (with the exception of conditions described in paragraph (f)), and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199.
>
> (e) Unprotected pipe must have cathodic protection if required by § 195.573(b).
>
> (f) Breakout tanks not in contact with soil, including tanks supported by concrete, asphalt, or other non-conductive foundations or double-bottom tanks with release barriers, are not subject to this requirement.
>
> **§ 195.565 How do I install cathodic protection on breakout tanks?**
>
> After October 2, 2000, when you install cathodic protection under § 195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels 79.49m3 capacity built to API Spec 12F (incorporated by reference, *see* § 195.3), API Std 620 (incorporated by reference, *see* § 195.3), API Std 650 (incorporated by reference, *see* § 195.3), or API Std 650's predecessor, Standard 12C, you must install the system in accordance with ANSI/API RP 651 (incorporated by reference, *see* § 195.3). However, you don't need to comply with API RP 651 when installing any tank for which you note in the corrosion control procedures established under § 195.402(c)(3) why complying with all or certain provisions of API RP 651 is not necessary for the safety of the tank. Pursuant to section 195.563(d) and (f), cathodic protection is not required for double-bottom tanks that have a release protection barrier included in its design and for breakout tanks that are not in contact with soil.

2. Limiting State Damage Prevention Exemptions[4]

Pipeline operators participate in state One Call Centers (OCC) in a united effort to protect underground infrastructure. However, certain stakeholder groups are exempt from participating in the one call process, allowing them to conduct excavation or earthmoving activities without prior locating and marking of underground assets from pipeline operators. States maintain a patchwork of exemptions for various stakeholder groups. These exemptions, especially for stakeholders that frequently excavate, disincentivize OCC notifications and threaten the safety of the pipeline network.[5]

Operators spanning multiple states have to navigate varied exemptions among different states, including state DOTs, agricultural, landowner, and railroad exemptions. The failure to click or call 811 before excavation remains the leading cause of pipeline excavation incidents, a trend often created by these state exemptions. Water and sewer work, often protected by an exemption, was the leading excavation activity causing damage to natural gas facilities in 2023[6]. Ohio, specifically, had over 800 unique damages to underground infrastructure due to no one call notification in 2023 alone. The state maintains an exemption for municipal crews which is the leading cause of excavations resulting in damage from sewer, road, sidewalk, drainage and water work. Over 99% (594 of 596) of those municipal crew damages impacted a natural gas pipeline facility.[7]

The state exemption issue has been raised by other federal agencies. A recent National Transportation Safety Board (NTSB) recommendation urged the state of Pennsylvania to modify existing legislation to require all facility owners or operators transporting steam or high-pressure materials to participate in the PA One Call System.[8]

Given the impact that state exemptions could have, stakeholders conducting deep earthmoving activities, such as tiling, should be required to place a one call notification prior to excavation. Additionally, states should, on an annual basis, publicly disclose the damages related to exemptions compared with those unrelated to exemptions to reassess the need for these exemptions and justify their continuance moving forward.

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[4] This section is in response to ANPRM Question #B.7. This proposal as well as the state practices and ticket size items closely reflects Section 18, "Excavation Damage Prevention" from the bipartisan 2023 PIPES Act Bill passed by the House Transportation and Infrastructure Committee.

[5] Repair costs from an incident caused by a stakeholder exemption can vary with incident size, property damage, location and more. Average costs can range between $200,000 and $500,000 for road grading or deep tilling incidents before factoring in legal fees or landowner payments.

[6] 2023 Common Ground Alliance DIRT Report, available at: https://commongroundalliance.com/Portals/0/Common-Ground-Alliance-DIRT-Report-2023-FINAL.pdf

[7] [7] 2023 DIRT Data for Ohio, available at: https://public.tableau.com/app/profile/trisha.schoof/viz/shared/9JMFBF9M2. Full data available at: https://commongroundalliance.com/dirt-dashboard

[8] NTSB Recommendation P-25-006 (Apr. 8, 2025).

§ 198.37 State one-call damage prevention program.

(~~d) The State must determine whether telephonic and other communications to the operational center of a one-call notification system under paragraph (c) of this section are to be toll free or not.~~ On an annual basis, states must publicly disclose the damages related to exemptions compared with those unrelated to exemptions. States must regularly reassess the need for state exemptions to the One Call process and justify their continuance in the annual PHMSA damage prevention program review.-OPS shall publish these metrics on its website.

3. Remove Prescriptive Threshold for Rupture Designation[9]

The Associations urge PHMSA to revise the definition of a "notification of potential rupture" and remove the "10% threshold within 15 minutes or less" in section 195.417(a)(1). Section 195.417(a)(1) provides that "a notification of potential rupture" includes observations by the public, local responders, or public authorities.[10] The regulation provides that a notification "occurs when an operator first receives notice of or observes" any of several broadly defined events, many of which are already addressed under existing control room abnormal operating condition procedures.[11] By definition, pipeline operators are required to take action based on unconfirmed information before the operator can verify its authenticity. By requiring immediate action based on unverified information from any source and requiring emergency notification before an operator can evaluate conditions, the regulation ignores established control room and pipeline safety requirements.

The Associations continue to have concerns with the "10 percent loss within 15 minutes" threshold. PHMSA requires an operator to take action when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in product demand, receipts, or deliveries. This approach places an undue burden on control room personnel and public safety answering points. Control room personnel are already required under sections 192.631 and 195.446 to monitor for, evaluate, and respond to unanticipated or abnormal conditions. Adding a "fixed" threshold like "10% in 15 minutes or less" without allowing for system-specific configurations and operational parameters increases the risk of triggering false potential rupture indications that could lead to unnecessary emergency notifications and possible unnecessary mobilization of responder resources.

[9] This section is in response to ANPRM Question #B.7.
[10] 49 C.F.R. § 195.417(a)(1).
[11] 49 C.F.R. § 195.417(b).

Pressure drops of 10 percent within 15 minutes can be frequent and may result from a variety of safe and acceptable conditions, including pipeline location, elevation, mode of operation, product deliveries, and product properties. Even with allowances in the rule for only considering "unanticipated and unplanned" pressure loss, the decision must be made by a controller or through logic built into systems to determine if it meets the criteria. Compliance with this approach does not necessarily lead to the best rupture detection methods.

PHMSA should allow operators more flexibility to define what conditions would constitute a potential rupture. PHMSA should also allow operators to evaluate other approaches, including the use of artificial intelligence, to monitor data and detect ruptures more effectively. PHMSA has acknowledged the growing role of artificial intelligence, machine learning, and external sensing technology in improving rupture detection accuracy. If these systems are already in place, PHMSA should consider these as meeting the intent of the rule.

The Associations recommend removing the "10% threshold" and replacing with "a significant unanticipated or unexplained pressure loss outside of the pipeline's normal range of operating pressures that occurs within a time interval of 15 minutes or less and may be an indication of a rupture condition."

§ 195.417 Notification of potential rupture.

(a) As used in this part, a notification of potential rupture means the notification to, or observation by, an operator (*e.g.,* by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of hazardous liquids or carbon dioxide from a pipeline:

(1) A~~n~~ significant unanticipated or unexplained pressure loss outside of the pipeline's normal range of operating pressures, as defined in the operator's written procedures ~~The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring~~ that occurs within a time interval of 15 minutes or less and may be a potential indication of a rupture condition. ~~unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to~~ Procedures developed for assessing if a potential rupture notification is required should include pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in product demand, receipts, or deliveries;

B. Tier 2 Priorities

1. Reform Accident Reporting[12]

a. Initial Volume Reporting

Currently, operators must report an initial estimate of the amount of product released, meeting certain event conditions in section 195.50, to the National Response Center (NRC), no later than one hour after confirmed discovery.[13] Unfortunately, the nature of this requirement almost always results in operators submitting estimates based on limited information. Pipeline accidents occur at all hours of the day, including night-time when there is little light available to estimate a release. The 1-hour reporting requirement provides little time to survey the extent of the volumes released, and potential impact of the release following initial confirmation. Weather conditions, such as snow or rain, may also impede estimates. Accidents originating from buried pipe, especially small seeper leaks, may produce underground release volumes not visible at the surface.

Operators are forced to submit estimates that lack critical information. The 1-hour reporting timeframe may not allow operators to follow their "written procedure to calculate and provide a reasonable initial estimate of the amount of released product" required by 195.52(c). Incorrect spill estimates are frustrating to both operators and public stakeholders. Estimates that are too low can spur criticism of an operator's response efforts and inability to effectively communicate information to external stakeholders. Estimates that are too high and are subsequently reduced as additional evaluation is conducted and information becomes available also bring unnecessary criticism. In both of these scenarios, the operator is using its available resources at the time the accident occurs to assess conditions, provide accurate information, and keep all potentially affected parties informed.

Operators recognize stakeholders, including first responders, local officials and regulators, need and want information on the release conditions to respond and communicate information in a timely manner. To meet this need and reduce the amount of incorrect information produced by PHMSA's current requirement, the Association propose moving to reporting a range of estimated volumes released when an accident occurs. The chosen ranges reflect the most critical information, such as whether this is a large, medium or small release requiring extensive or modest emergency response and resources. To accomplish this goal, the Associations propose the following changes to regulation:

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[12] This section is in response to ANPRM Question #B.4.

[13] 49 C.F.R § 195.52(a).

§ 195.52 Immediate notice of certain accidents.

(a) ***Notice requirements.*** At the earliest practicable moment following discovery, of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in § 195.50, but no later than one hour after confirmed discovery, the operator of the system must give notice, in accordance with paragraph (b) of this section of any failure that…

~~(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;~~

(b) Information required. Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800-424-8802 (in Washington, DC, 202-267-2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

...

(6) An ~~I~~initial estimated range of ~~-~~the amount of product released as calculated in accordance with paragraph (c) of this section and using the following ranges ~~Operators may report a range of estimated product released~~:

(i) less than 1 barrel;

(ii) more than 1 barrel but less than 500 barrels, or

(iii) more than 500 barrels.

(c) Calculation. A pipeline operator must have a written procedure to calculate and provide a reasonable initial range of the estimated ~~of the~~ amount of released product.

b. 48-Hour Follow-up Report

As part of this priority, the Associations request that PHMSA also modify the requirement in section 195.52(d) that operators must automatically submit a follow up report to the NRC within 48 hours.[14] This is an undue burden. PHMSA should require a follow up report only to the extent necessary (*i.e.,* a significant change in information occurs). PHMSA should assume that if no follow up call is made, then the initial report is confirmed by default. PHMSA should also allow for initial reports to be rescinded in follow-up reports where information obtained as the response efforts are implemented indicate that the initial volume estimates were incorrect and that the volume of product released did not exceed the reporting threshold limits for both on property and off-property accidents. The Associations propose the following changs to section 195.52(d):

[14] 49 C.F.R. § 195.52(d).

§ 195.52 Immediate notice of certain accidents.

(d) ***New information.*** Within 48 hours after the confirmed discovery of an accident, to the extent practicable and necessary, an operator must revise ~~or confirm to~~ its initial ~~telephonic~~ notice required in paragraph (b) of this section with a revised estimated range of the amount of product released, location of the failure, time of the failure, a revised estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the accident or extent of the damages. If there are no changes or revisions to the initial report, the operator need not file an additional notice under this paragraph ~~must confirm the estimates in its initial report~~. Operators may rescind immediate notification of releases where supplemental information and data confirm that estimated volumes released are below volume reporting threshold values established in § 195.50(b).

c. Accident Reporting Threshold

The Associations urge PHMSA to modify the reporting threshold for hazardous liquid accidents. The Agency currently requires operators to report a release of hazardous liquid or carbon dioxide that results in the release of 5 gallons or more.[15] The Associations support reporting accidents to the National Response Center where there may be a potential for impacting local communities and where local first responders need to be notified of an accident. However, PHMSA should create a separate reporting threshold for releases that are contained on facility property and therefore, are less impactful. In addition, the Associations recommend removing the estimated amount of property damage as a criterion for contacting NRC. The value of property damage alone is not a consistent and reliable indicator of incident significance and should not be used as a basis to contact NRC and potentially mobilize response resource. However, we support retaining that value as a requirement to submit an accident report within 30-days after an event occurs and any supplemental accident reports. PHMSA should retain the 5-gallon threshold for releases that are not contained on company-controlled property and could impact people or the environment but increase the threshold to 5 barrels for those releases that are contained on company controlled property and do not affect people or the environment.

The Associations recommend the following amendments:

§ 195.50 Reporting accidents.

[15] 49 C.F.R. § 195.50.

An accident report is required for each failure in a pipeline system subject to this part in which there is a release of hazardous liquid or carbon dioxide transported resulting in any of the following:

(a) Explosion or fire not intentionally set by the operator;
(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, in any area that is not on property owned or controlled by the operator and may impact the public or the environment, except no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:
    (1) Not otherwise reportable under this section;
    (2) Not one described in § 195.52(a)(4);
    (3) Confined to company property or pipeline right-of-way; and
    (4) Cleaned up promptly;
(c) Release of 5 barrels (0.8 cubic meters) or more of hazardous liquid or carbon dioxide that are totally confined to operator company property, such as but not limited to, breakout tank facility/terminal, pump/compressor station, meter station, and valve sites;
(d) Death of any person;
(~~d~~e) Personal injury necessitating hospitalization;
(~~e~~f) Estimated property damage, including cost of clean up and recovery, value of loss product, and damage to the property of operator or others, or both, exceeding $~~50,000~~149,700. For adjustments for inflation observed in calendar year 2026 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix D to part 195.

The Associations recommend similar changes to Part 191.

2. Allow Check Valves for Rupture Mitigation[16]

For hazardous liquid pipelines, check valves offer greater levels of safety by shutting immediately upon pressure loss rather than a remotely operated valve that requires identification and closure time. PHMSA's regulations that were approved under the recent Valve Rule recognize the use of check valves as an alternative equivalent technology for Rupture Mitigation Valves (RMVs) and other forms of automatic shut-off valves (ASVs) for mainlines and laterals segments and require that these valves be inspected, operated, and remediated in accordance with § 195.420, including for closure and leakage, to ensure operational reliability.

[16] This section is in response to ANPRM Question # B.7.

In PHMSA's Frequently Asked Questions posting on its web page, PHMSA recognizes that for hazardous liquid pipelines, a check valve that allows liquid flow in one direction and automatically prevents flow in the other (functioning similarly and equivalently to an ASV) may be used as an alternative equivalent technology when positioned to stop flow into the shut-off segment. Additionally, § 195.450 defines a check valve as an Emergency Flow Restriction Device (EFRD) and an acceptable technology in the § 195.452 integrity management regulations to protect HCAs for 24+ years prior to recent RMV rules. The Associations recommend that check valves be specifically added to the current regulations to clarify that they can be considered for rupture mitigation on liquid pipelines.

The Associations recommend the following changes:

> **§ 195.418 Valves: Onshore valve shut-off for rupture mitigation.**
>
> (a) ***Applicability.*** For newly constructed and entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, as defined at § 195.2, with diameters of 6 inches or greater that could affect high-consequence areas or are located in high consequence areas (HCA), and that have been installed after April 10, 2023, an operator must install or use existing rupture-mitigation valves (RMV), as defined at § 195.2, check valves, or alternative equivalent technologies, according to the requirements of this section and § 195.419. RMVs, check valves, and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment in service. An operator may request an extension of this 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacements, even those that do not otherwise directly involve the addition or replacement of a valve.

3. Include Dredging or Marine Excavation in "Excavation Activities" Damage Prevention Definition[17]

The current definition of "excavation activities" in sections 192.614 and 195.442 only includes land-based or ground activities. The term is defined in each section as "excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations."[18] Excavation also occurs in marine environments and in proximity to submerged pipelines. Federal law does not require one call notification prior to digging for this work. However, marine construction activities near pipelines have led to significant incidents, endangering personnel, the pipeline and the

[17] *Id.*
[18] 49 C.F.R. §§ 192.614(a) and 195.442(a).

environment. In 2021, the NTSB issued safety recommendations to PHMSA encouraging the development of practices and processes for pipeline operators and dredging companies to obtain and use accurate pipeline location data during one-call locating activities.[19] The Associations recommend the following modifications to sections 192.614 and 195.442:

> **§ 192.614 Damage prevention program.**
>
> (a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purposes of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, deep earthmoving such as tiling, dredging or marine construction, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations, submerged or land-based or any marine activity that impacts the water bottom.
>
> **§ 195.442 Damage prevention program.**
>
> (a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, deep earthmoving such as tiling, dredging or marine construction, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations, submerged or land-based or any marine activity that impacts the water bottom.

The Associations also recommend that PHMSA modify the definition for "excavation" found in Part 196 to include a reference to section 195.442. Currently, the definition only references section 192.614. Given that many excavators primarily focus on the requirements in Part 196, it is essential that the regulatory text contain accurate and appropriate cross references. The Associations provide the following recommended modification:

> **§ 196.3 Definitions**
>
> *Excavation* refers to excavation activities as defined in § 192.614 and § 195.442, and covers all excavation activity involving both mechanized and non-mechanized equipment, including hand tools.

C. Tier 3 Priorities

[19] NTSB Safety Recommendations P-21-018 and P-21-019 (Dec. 7, 2021).

1. Require State Enforcement of Damage Prevention Violations[20]

State enforcement of damage prevention violations represents a valuable opportunity for PHMSA to provide federal leadership in infrastructure protection. Effective federal oversight of state damage prevention programs would limit exemptions for certain stakeholder groups and excavation activities, increase OCC notifications, and enhance pipeline infrastructure safety. While states may have enforcement language in legislation, many do not effectively, actively and consistently enforce violations of state one call laws. Ineffective and inconsistent enforcement fails to prevent a recurrence of these violations, leading to further incidents, fatalities and injuries, and lost products and asset damage. Inactive enforcement also represents a missed income stream for states to recoup from repeat or negligible offenders. In lieu of monetary penalties, particularly for first-time offenders, excavation training and education would help prevent recurrence. Enhanced reporting and performance measures on enforcement will demonstrate the effectiveness of these efforts in raising state revenues while increasing pipeline safety. PHMSA should also condition federal grant funding on states' actually enforcing violations in an effective, active and consistent manner. These metrics should be available to the public via the PHMSA website.

§ 198.35 Grants conditioned on adoption of one-call damage prevention program.

In allocating grants to State agencies under the pipeline safety laws, (49 U.S.C. 60101 *et seq.*), the Secretary considers whether a State has adopted or is seeking to adopt a one-call damage prevention program in accordance with § 198.37. If a State has not adopted or is not seeking to adopt such program, the State agency may not receive the full reimbursement to which it would otherwise be entitled. The Secretary also considers state adoption of leading damage prevention practices such as tolerance zone requirements, emergency excavation notification requirements, operator personnel on site requests, damage reporting, white lining, positive response, locatable capabilities for newly installed underground facilities, limiting ticket geographic size and training for excavators and locators.

§ 198.37 State one-call damage prevention program.

(c) Excavators must be required to notify the operational center of the one-call notification system that covers the area of each intended excavation activity (as defined by 49 CFR § 192.614(a) and 49 CFR § 195.442(a)) and provide the following information:

(1) Name of the person notifying the system.

[20] This section is in response to ANPRM Question # B.7.

(2) Name, address and telephone number of the excavator.

(3) Specific location, starting date, and description of the intended excavation activity. The geographic extent of the location request of the intended excavation activity shall not exceed the capacity to conduct the excavation in the specified timeframe and in compliance with state requirements.

However, an excavator must be allowed to begin an excavation activity in an emergency but, in doing so, required to notify the operational center at the earliest practicable moment.

(g) Persons who operate one-call notification systems or operators of underground pipeline facilities participating or required to participate in the one-call notification systems must be required to notify the public and known excavators in the manner prescribed by § 192.614 (b)(1) and (b)(2) of this chapter of the availability and use of one-call notification systems to locate underground pipeline facilities. ~~However, this paragraph does not apply to persons (including operator's master meters) whose primary activity does not include the production, transportation or marketing of gas or hazardous liquids.~~

(h) Operators of underground pipeline facilities (other than operators of interstate transmission facilities as defined in the pipeline safety laws (49 U.S.C. 60101 *et seq.*), and interstate pipelines as defined in § 195.2 of this chapter), excavators and persons who operate one-call notification systems who violate the applicable requirements of this subpart must be subject to civil penalties and injunctive relief that are substantially the same as are provided under the pipeline safety laws (49 U.S.C. 60101 *et seq.*).–States must enforce violations of one-call requirements consistently and effectively to prevent recurrence, particularly from repeat or negligent offenders, in order to receive the full reimbursement to which it would otherwise be entitled. Excavator offenders must complete damage prevention training as an option, with repeat offenses triggering monetary violations. As part of the violation process, the agency of jurisdiction should notify the complainant that the state authority has received and addressed the complaint. The process should be clearly defined in either state law or within the submittal location.

2. Right of Way Maintenance Flexibility for Conservation Activities[21]

The Associations seek improved clarity in complying with both conservation, habitat and vegetation management programs and required section 195.412 right-of-way inspections. PHMSA should allow operators to use alternative methods for maintaining rights-of-way if that program achieves a level of safety at least equivalent to the level of safety required in

[21] This section is in response to ANPRM Question # B.7.

section 195.412. Frequent ground inspections or aerial overflights can disrupt sensitive ecosystems and hinder efforts to promote biodiversity, erosion control and pollinator support. Operators could accomplish both objectives by using integrated vegetation management, reduced mowing, seeding or planting to support pollinators' habitat, maintenance practices to promote early successional vegetation or limit pollinator disturbances, or judicious use of herbicides. PHMSA should also allow operators to seek right-of-way inspection variances for directionally drilled rights-of-way that have conservation, habitat or vegetation management initiatives on account of the reduced risk profile. Adding clarity that alternative maintenance approaches are compliant would prevent inconsistent enforcement while supporting environmental stewardship.

> **§ 195.412 Inspection of rights-of-way and crossings under navigable waters.**
>
> (a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way.
>
> (1) Operators may utilize alternative methods for maintaining rights-of-way for pipelines and other pipeline facilities subject to a voluntary program carried out by the operator if such an alternative method achieves a level of safety equivalent to the level of safety required in section (a) and (b). Such program could include integrated vegetation management, reduced mowing, seeding or planting to support pollinators' habitat, maintenance practices to promote early successional vegetation or limit pollinator disturbances, and judicious use of herbicides.
>
> (b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.
>
> (1) Operators of drilled pipelines employing alternative ROW maintenance programs may apply for a variance in inspection intervals based on the reduced risk profile of these underground assets.

3. Flexibility on Point-to-Point Verification[22]

[22] This section is in response to ANPRM Question # B.7.

Section 195.446(c)(2) requires verification of all safety-related alarm set-points and descriptions every time associated field instruments are calibrated or changed, and at least once per calendar year (not to exceed 15 months). This prescriptive requirement imposes significant, often unjustified workload on control room, I&E, field operations and SCADA staff — particularly for operators with large numbers of instruments. Calibration activities by definition do not alter alarm set-points or descriptions. When those values are controlled via centralized SCADA or DCS systems, they remain unchanged unless intentionally modified; a process requiring a management of change (MOC) and a point to point under existing 49 C.F.R. § 192.631(c)(2) and 195.446(c)(2). Forcing re-verification during routine calibration effectively mandates continuous, redundant point-to-point checks, which provides no meaningful safety benefit and detracts from high-value engineering and alarm rationalization work. A risk-based, MOC-driven verification process would better align with existing alarm management practices, including API RP 1167 and ISA-18.2 standards. Such an approach ensures alarm integrity while reducing unnecessary compliance burdens and freeing up resources for more impactful safety activities.

The Associations recommend the following revisions:

> **§ 195.446 Control room management.**
>
> (c) ***Provide adequate information.*** Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following…
>
> (2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved. Operators should conduct a point to point where alarm setpoints and descriptions are verified only when a change condition occurs which triggers a point to point and management of change, including physical change in equipment, physical move, or configuration change. ~~and when other changes that affect pipeline safety are made to field equipment or SCADA displays;~~
>
> (e) ***Alarm management.*** Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:
>
> (3) Verify the correct safety-related alarm set-point values and alarm descriptions when associated field equipment ~~are calibrated or changed and at least once each calendar year, but at intervals not to exceed 15 months~~ is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays

D. Additional Industry Priorities Mentioned in Other Regulatory Actions

1. Fulfill Congressional Mandate for Rulemaking on Idled Pipe Operating Status[23]

PHMSA should not regulate idled pipe the same as active pipelines. Idled pipe presents a reduced safety risk. By definition, idled pipelines do not actively carry hazardous materials and are disconnected from sources that allow for transportation of hazardous materials – one could argue that idled lines, if disconnected from the system and having no product contained within them, would not be subject to Part 195 regulations. As a result, the regulations for idled pipe should be appropriately tailored to reflect the reduced risk of a possible accident.

Congress directed PHMSA in section 109 of the PIPES Act of 2020 to promulgate regulations prescribing regulations for idled pipelines.[24] To date, PHMSA has not issued such a proposal. When an idled pipeline is returned to active service, it must comply with all applicable pipeline safety requirements. While it is idled, which often is for an extended duration, it is not reasonable to continue applying rigorous requirements and agency oversight to an asset that poses no threat to the public or environment.

The Associations encourage PHMSA to add a definition in section 195.2 for idle pipe and complete the mandated rulemaking. That term should be defined as follows:

> **§ 195.2 Definitions.**
>
> *Idled Pipe* means currently removed from service, disconnected from all active pipe, and purged from hydrocarbons.

As discussed in this comment document, PHMSA should also incorporate API RP 1181 and reference that recommended practice in section 195.402 requirements applicable to idled pipe.

2. Reform the Special Permit Program[25]

The Associations seek three key changes to PHMSA's special permit process: (1) establishing a firm timeline for the review process; (2) setting a longer renewal period; and (3) tailoring

[23] This section is in response to ANPRM Question # B.1.
[24] 49 U.S.C § 60143(b).
[25] This section is in response to ANPRM Question # A.4.

conditions to the waiver application. The Associations recognize, since this ANPRM was issued, PHMSA is undertaking a separate rulemaking to address special permits.[26] The Associations will comment on that specific rulemaking, and also offer these comments as part of this broader deregulatory ANPRM.

a. Reasonable Timeframe for Review Process

Historically, operators have waited years for PHMSA to make a decision on special permit applications. It is difficult to make operational and business decisions when faced with such a lengthy and uncertain review process. PHMSA should limit its review period to 9 months running from when the Agency provides public notice of its intent to consider the application. This is an appropriate amount of time to review the application and conclude whether the waiver request would not be inconsistent with pipeline safety.

The Associations recommend the following changes to section 190.341(d)(2).

> **§ 190.341 Special permits.**
>
> (d) ***How does PHMSA handle special permit applications?***
> (1) ***Public notice.*** Upon receipt of an application or renewal of a special permit, PHMSA will provide notice to the public of its intent to consider the application and invite comment. In addition, PHMSA may consult with other Federal agencies before granting or denying an application or renewal on matters that PHMSA believes may have significance for proceedings under their areas of responsibility.
>
> (2) ***Grants, renewals, and denials.*** If the Associate Administrator determines that the application complies with the requirements of this section and that the waiver of the relevant regulation or standard is not inconsistent with pipeline safety, the Associate Administrator may grant the application, in whole or in part, for a period of time from the date granted. Conditions may be imposed on the grant if the Associate Administrator concludes they are necessary to assure safety, environmental protection, or are otherwise in the public interest. If the Associate Administrator determines that the application does not comply with the requirements of this section or that a waiver is not justified, the application will be denied. Whenever the Associate Administrator grants or denies an application, notice of the decision will be provided to the applicant. PHMSA will post all special permits on its Web site at *http://www.phmsa.dot.gov/*. The Associate Administrator shall complete the review of each application not later than 9 months after the date of the public notice under paragraph (1).

[26] 90 Fed. Reg. 28,590.

b. Fifteen-Year Renewals

PHMSA uses either five-year or ten-year expiration dates for special permits.[27] While operators understand the need to evaluate whether a permit continues to "not be inconsistent with pipeline safety", a five or ten-year duration for the life of a permit is not long enough to ensure certainty for infrastructure investment and unnecessarily increases administrative burdens. In some cases, an operator will seek a special permit as part of the development of a new pipeline system. Capital costs for new pipelines can range into billions of dollars. Operators must have regulatory certainty that they can operate the new system for a period of time long enough to recover its costs. Lengthening the renewal period for a special permit will help provide the regulatory certainty needed to encourage new energy infrastructure development, making a way for PHMSA to fulfill Executive Order 14154 to unleash American energy.[28]

A longer and more consistent renewal cycle would reduce burdens on PHMSA and operators and enhance service continuity and reliability for customers. Operators must file an application for renewal no later than 6 months prior to the expiration date of the permit.[29] It takes substantial resources to prepare and review a special permit application. Having such a limited period of time to use the permit creates resource strain for both operators and PHMSA personnel.

The Associations recommend the following regulatory amendments:

> **§ 190.341 Special permits.**
>
> **(e)** ***How does PHMSA handle special permit renewals?***
> (1) The grantee of the special permit must apply for a renewal of the permit 180 days prior to the permit expiration.
>
> (2) If, at least 180 days before an existing special permit expires the holder files an application for renewal that is complete and conforms to the requirements of this section, the special permit will not expire until final administrative action on the application for renewal has been taken:
>
> (i) Direct fax to PHMSA at: 202-366-4566; or
>
> (ii) Express mail, or overnight courier to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590.
>
> (3) If granted, the renewal period is a minimum of fifteen years.

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[27] *See* PHMSA-2021-0042 (Renewal from 2021 to 2031); *See also,* PHMSA-RSPA-2003-15122 (Original permit was issued in 2010 and then renewed on a five-year basis from 2015-2020 and 2020-2025).
[28] 90 Fed. Reg. 8,353.
[29] 49 C.F.R. § 190.341(e).

c. Unrelated Permit Conditions

While the Associations also support adding commonsense language to section 190.341 establishing that permit conditions must have a direct connection to the risk posed by the waiver application, the Associations recognize that PHMSA has issued a proposed rule modifying section 190.341 accordingly. The Associations support PHMSA's proposed rule on this subject and encourage PHMSA to finalize it as soon as possible.

3. Targeted Update of Carbon Dioxide (CO_2) Pipeline Safety Requirements[30]

Current PHMSA regulations prescribe hundreds of requirements on the construction, inspection, maintenance, monitoring and accident response for CO_2 pipelines. PHMSA inspects and enforces compliance on pipeline operators violating federal CO_2 pipeline safety requirements. Government pipeline safety data collected by PHMSA and publicly available demonstrates CO_2 pipeline accidents are rare and declining. CO_2 pipelines have a lower incident rate per mile than both crude oil and refined products pipelines. This overall safety performance record does not support comprehensive changes to federal CO_2 pipeline safety requirements. While the Associations recognize PHMSA developed a Notice of Proposed Rulemaking (NPRM) for CO_2 pipelines in January 2025, the prepublication draft was overreaching and with questionable safety benefits. Many of the proposed requirements would have been overly onerous and infeasible for CO_2 pipeline operators.

However, the Associations do recognize that pipeline accidents provide opportunities for learning and improving pipeline safety. The 2020 Satartia, Mississippi pipeline accident indicated areas where pipeline operators could improve CO_2 pipeline safety performance, specifically around CO_2-specific dispersion modeling and outreach to emergency responders. The Associations also support clarifying that federal CO_2 pipeline safety requirements extend to pipeline transportation of CO_2 in the gaseous state. For these reasons, the Associations support a new targeted PHMSA rulemaking updating CO_2 pipeline requirements in these key areas.

E. Additional Recommendations for Improving the Efficiency and Effectiveness of PHMSA Regulations

1. Inspections & Enforcement[31]

a. Requests for Information

[30] This section is in response to ANPRM Question # B.1.
[31] *Id.*

Section 190.203(c) allows the Associate Administrator or Regional Director to request further information to determine appropriate action.[32] The Associations have identified two burdens with this regulation: (1) the deadlines for responses and (2) the general use of requests for information. While the regulation provides a default deadline of 30 days for responses, PHMSA frequently exercises the option to specify an alternative deadline by shortening it to less than 15 days. Pipeline facilities have become increasingly complex over time due to technological advancements and regulatory developments. Consequently, responding to a request for information may require operators to identify, gather, review, and compile information and data that is complex in nature. Further, asset information can be quite voluminous and thus stored at offsite storage facilities. Responding to information requests, therefore, can be resource- and time-intensive and may take operator staff away from executing normal and daily operational duties. Operators may also be required to have their staff work overtime to meet the required deadline. The Associations urge PHMSA to extend the response time deadline in § 190.203(c) from 30 days to 45 days, which would alleviate undue burdens.

In addition, some regions are using the request for information tool to supplement the record in an enforcement case. PHMSA should clarify its regulations to prevent this practice. The Associations recommend the following modifications to § 190.203(c):

> **§ 190.203 Inspections and investigations.**
>
> (c) If the Associate Administrator or Regional Director believes that further information is needed to determine appropriate action, the Associate Administrator or Regional Director may notify the pipeline operator in writing that the operator is required to provide specific information within ~~30~~ 45 days from the time the notification is received by the operator, ~~unless otherwise specified in the notification~~. The notification must provide a reasonable description of the specific information required. An operator may request an extension of time to respond by providing a written justification as to why such an extension is necessary and proposing an alternative submission date. A request for an extension may ask for the deadline to be stayed while the extension is considered. General statements of hardship are not acceptable bases for requesting an extension. A request for information cannot be used during a pending enforcement proceeding.

A deadline shorter than 30 days should only be used in the context of accident investigations.

Many PHMSA inspectors make general requests for electronic copies of all documents used during pipeline inspections. This is an apparent overreach of their authority and unduly burdens operators with redacting at times thousands of documents before providing to the agency to protect company confidential information. PHMSA should specify that "make available"

[32] 49 C.F.R. § 190.203(c).

means providing an inspector access to review documents while on site and while during the inspection.

The Associations recommend the following modifications to § 190.203(e):

§ 190.203(e) Inspections and investigations.

(e) If a representative of the U.S. Department of Transportation inspects or investigates an accident or incident involving a pipeline facility, the operator must make available to the representative all records and information that pertain to the event in any way, including integrity management plans and test results. The operator must provide all reasonable assistance in the investigation. Any person who obstructs an inspection or investigation by taking actions that were known or reasonably should have been known to prevent, hinder, or impede an investigation without good cause will be subject to administrative civil penalties under this subpart. Records can be made available by providing PHMSA access to the records for electronic or physical review.

PHMSA should amend section 195.60 (Operator assistance in investigation) to allow for reasonable time periods to provide records to PHMSA.

The Associations recommend the following modifications to § 195.60:

§ 195.60 Operator assistance in investigation

If the Department of Transportation investigates an accident, the operator involved shall make available, as soon as practicable, to the representative of the Department all records and information that in any way pertain to the accident, and shall afford all reasonable assistance in the investigation of the accident.

b. Initiating a New Inspection

PHMSA should also codify the prohibition in the DOT General Counsel Enforcement Memo restricting the Agency from initiating a new inspection of a party after commencing an enforcement action, absent a showing of good cause.[33] Codification of this prohibition would not only eliminate inefficiencies, but would also protect an operator's right to due process.

The Associations recommend the following modifications to § 190.203(f):

§ 190.203(f) Inspections and investigations.

(f) When OPS determines that the information obtained from an inspection or from other appropriate sources warrants further action, OPS may initiate one or more of

[33] DOT General Counsel Enforcement Memo, at ¶ 19.

the enforcement proceedings prescribed in this subpart. OPS may not initiate a new inspection of the same operator during a pending enforcement action.

c. Warnings

PHMSA should allow adjudications of warnings. The Associations previously raised concerns in a 2013 rulemaking, regarding the lack of clarity in the agency's consideration of warning letters.[34] In response to those comments, the Agency modified Section 190.205 to explicitly allow a respondent to submit a response to a warning, but maintained that it was under no obligation to adjudicate warnings to determine if they were supported by the facts and law.[35] However, historically, PHMSA has withdrawn warning letters.[36] PHMSA also continues to advise its enforcement personnel in its Enforcement Manual that warning letters *can be withdrawn*.[37]

If a respondent identifies inaccuracies with either the law or the facts, as applied in a warning, and requests a hearing, PHMSA should allow the hearing to occur. If the operator contests the warning but does not request a hearing, PHSMA should review the response and rescind the warning letter if there are inaccuracies with either OPS's application of the law or the facts. A blanket "no adjudications" rule is inconsistent with the due process considerations in the DOT General Counsel memo.[38] The Associations urge PHMSA to update its Enforcement Manual to memorialize the Agency's obligation to adjudicate contested warnings and then subsequently revise section 190.3 to add warnings as a type of enforcement case that a Presiding Official can review.

§ 190.205 Warnings.

Upon determining that a probable violation of 49 U.S.C. 60101 *et seq.,* 33 U.S.C. 1321(j), or any regulation or order issued thereunder has occurred, the Associate Administrator or a Regional Director may issue a written warning notifying the operator of the probable violation and advising the operator to correct it or be

[34] Comments from the LEPA (formerly known as the Association of Oil Pipe Lines) and the API in response to PHMSA's Pipeline Safety: Administrative Procedures; Updates and Technical Corrections Notice of Proposed Rulemaking (Docket No. PHMSA-2012-0102), available at PHMSA-2012-0102-0004_attachment_1.pdf.
[35] 78 Fed. Reg. 58,897, 58,900.
[36] *In the Matter of Alyeska Pipeline Company*, CPF No. 5-2008-5001W (Feb. 27. 2008); *In the Matter of Gas Transmission Northwest LLC,* CPF No. 5-2012-1004W (Feb.21, 2012); *In the Matter of Colorado Interstate Gas,* CPF No. 5-2015-1001W (Jan. 15, 2015); *In the Matter of Buckeye Partners,* CPF No. 4-2012-5015 (Oct. 18, 2012); *In the Matter of Conoco Phillips,* CPF No. 5-2004-5009 (Sep. 20, 2006); *In the Matter of Natural Gas Pipeline Co.,* CPF No. 23103 (Aug. 18, 1997); *In the Matter of ExxonMobil,* CPF No. 5-2005-5008 (Jan. 9, 2007); *In the Matter of Bridger Pipeline,* CPF No. 5-2009-5034 (Aug. 30, 2012); *In the Matter of Kinder Morgan, Inc.,* CPF No. 5-2007-1008 (Sep. 1, 2009).
[37] *See* section 4.1.5.1 of the Enforcement Manual.
[38] DOT General Counsel Enforcement Memo, at 2 (definition for Due Process).

subject to potential enforcement action in the future. The operator may submit a response to a warning, but is not required to. ~~An adjudication under this subpart to determine whether a violation occurred is not conducted for warnings.~~

§ 190.3 Definitions.

Presiding Official means the person who conducts any hearing relating to civil penalty assessments, compliance orders, orders directing amendment, safety orders, warning letters or corrective action orders and who has the duties and powers set forth in § 190.212.

d. Location of Hearings

The Associations request that PHMSA revise section 4 of its Enforcement Manual to clarify the location of hearings and then subsequently amend Part 190 to clarify the process for scheduling an administrative hearing. While section 190.212(b) provides that the presiding official will set the date, time, and location of the hearing,[39] section 190.211(c) controls where those hearings will occur. Section 190.211(c) provides that "in-person hearings will normally be held at the office of the appropriate OPS Region."[40] For decades, PHMSA has scheduled hearings at its regional offices. However, recently, PHMSA's Presiding Official has been scheduling in-person hearings only at PHMSA's headquarters in Washington, D.C. This requires OPS region staff and operator representatives to travel to Washington, D.C. instead of the OPS region office, where the operator may be located as well, adding additional time and expense. Washington, D.C. should be the exception, not the rule. The Associations request that PHMSA update section 4.1.7.2 of its Enforcement Manual clarifying that the hearings should occur at the appropriate OPS region consistent with section 190.211(c), or at a location mutually agreed upon by OPS and the respondent. The Associations also seek the following clarifying amendments to sections 190.211(c) and 190.212(b):

§ 190.211 Hearing.

(c) ***Telephonic and In-Person Hearings.*** A telephone hearing will be held if the amount of the proposed civil penalty or the cost of the proposed corrective action is less than $25,000, unless the respondent or OPS submits a written request for an in-person hearing. In-person hearings will ~~normally~~ be held at the office of the appropriate OPS Region, or at a mutually agreed upon location. Hearings may be held by video~~ tele~~conference upon request of the Respondent ~~if the necessary equipment is available to all parties.~~

[39] 49 C.F.R. § 190.212(b).
[40] *Id.* at § 190.211(c).

§ 190.212(b) Presiding official, powers, and duties.

(b) ***Time and place of the hearing***. The Presiding Official will set the date, time and location of the hearing based on the requirements set forth in section 190.211(c). To the extent practicable, the Presiding Official will accommodate the parties' schedules when setting the hearing. Reasonable notice of the hearing will be provided to all parties.

e. Requirements for Pre-Hearing Submissions

The Associations also seek clarification of section 190.211(d) governing pre-hearing submissions. That regulation provides that "[i]f OPS or respondent *intends* to introduce materials…not already in the case file, the material must be submitted to the Presiding Official and the other party at least 10 days prior to the date of the hearing, unless the Presiding Official sets a different deadline or waives the deadline for good cause."[41] Pre-hearing submissions are not required but are an option for both parties. Yet, recently, PHMSA's Presiding Official has been directing both parties to submit the following set of materials prior to a hearing – (1) a statement of facts; (2) a list of all agreed upon facts; (3) the respondent's defenses; (4) a witness list that includes the anticipated length and description of each witness' anticipated testimony sufficient to show how the anticipated testimony may prove or disprove a fact significant of the case; and (5) a copy of the exhibits with an exhibit index.[42] Not only is a pre-hearing submission optional but some of the requested materials are duplicative of information already included in the case file[43] or provided in respondent's response document per 190.211(b). PHMSA should update its Enforcement Manual to confirm that pre-hearing submissions are not required as set out in section 190.211(d).

f. Deadlines for Pre-Hearing Submissions

Finally, the Associations seek clarity on the deadlines for a pre-hearing submission. Section 190.211(d) provides that "[pre-hearing] material must be submitted to the Presiding Official and the other party <u>at least 10 days prior to the hearing</u>, unless the Presiding Official sets a different deadline or waives the deadline for good cause."[44] In recent cases, the Presiding Official has begun requiring the parties to submit their pre-hearing materials well in advance of the scheduled hearing. The parties may be actively engaged in parallel settlement negotiations during this period, thus requiring the parties to potentially halt negotiations to gather and prepare their pre-hearing materials. The Associations acknowledge that section 190.211(d) gives the Presiding Official discretion on setting the deadline for pre-hearing

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[41] *Id.* at § 190.211(d).
[42] *See* various scheduling letters issued after March 27, 2025.
[43] 49 C.F.R. § 190.209.
[44] 49 C.F.R. § 190.211(d)(emphasis added).

submission, however, requiring materials to be submitted so far in advance of the hearing is unreasonable and inconsistent with the intent of section 190.211(d).

The Associations recommend that PHMSA amend 190.211(d) as follows:

> **§ 190.211 Hearing.**
>
> **(d) Pre-hearing submissions.** If OPS or the respondent intends to introduce material, including records, documents, and other exhibits not already in the case file, the material must be submitted to the Presiding Official and the other party at least 10 days prior to the date of the hearing, unless the Presiding Official ~~sets a different deadline or~~ waives the deadline for good cause.

g. Availability of Recommended Decisions

Contrary to the informal adjudication process of other DOT operating modes and other Federal agencies,[45] PHMSA does not provide the recommended decision to the respondent. To allow for greater transparency in the adjudications process, the Associations urge PHMSA to require that the recommended decision be provided to the respondent at the same time it is forwarded to the Administrator.

PHMSA has stated in response to previous requests that recommended decisions are "a deliberative and pre-decisional document,"[46] and a draft decision.[47] The Agency has also concluded that the "Associate Administrator is not required by the pipeline safety laws to provide an operator with a presiding official's recommendation." [48] This approach raises fairness and due process concerns.

The presiding official's recommended decision is a result of his or her evaluation of the case file, including material evidence presented at the hearing.[49] Particularly, since the presiding official is tasked with assessing credibility of witnesses at the hearing, and the Associate Administrator does not attend hearings nor is a transcript required, it is important from a due process perspective that PHMSA provide the recommended decision to the respondent. An

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[45] 49 C.F.R. § 209.323 through 327 (FRA regulations consider an initial decision, finality of decision, and appeal process); 49 C.F.R. § 13.232 (FAA's regulations outlining the requirements for the issuance of an initial decision at the conclusion of a hearing); 40 C.F.R. § 22.27(c) (EPA regulations contemplate an initial decision, a motion to reopen a hearing, and an appeal process); 29 C.F.R. § 38.112 (DOL regulations provide procedures for an initial decision and final decision); 21 C.F.R. Part 12, Subpart G (FDA's procedures initial and final decisions).

[46] *In the Matter of Sunoco Logistics Partners, LP,* CPF No. 1-2007-5001 (Oct. 22, 2009) at 2; *See also, In the Matter of ExxonMobil Pipeline Co.,* CPF No. 4-2013-5027 (Apr. 1, 2016) at 13.

[47] Administrative Procedures; Updates and Technical Corrections, 78 Fed. Reg. 58897 at 58901 (Sept. 25, 2013).

[48] *In the Matter of Sunoco Logistics Partners, LP,* CPF No. 1-2007-5001 (Oct. 22, 2009) at 2.

[49] The Presiding Official regulates the course of the hearing, including the giving the parties an opportunity to offer material and relevant testimony. 49 C.F.R. § 190.211(e). The Presiding Official then prepares a recommended decision in the case based on a review of the case file. 49 C.F.R. § 190.211(h). This would include a review of any material, such a witness testimony, provided during the hearing. 49 C.F.R. § 190.209(b)(6).

assessment of witness testimony is a critical factor of the presiding official's evaluation[50] and one that cannot be conferred to the Associate Administrator. Operators are unaware of whether changes have been made between the time the recommended decision is drafted by the presiding official and the Associate Administrator's issuance of an order. If there are any key differences in conclusions between the presiding official's recommended decision and the Associate Administrator's final decision, the respondent, and potentially any reviewing court, should be permitted to view both documents to ensure transparency in the informal adjudications process. Other agencies, including DOT modes, provide an initial decision to the Respondent.[51] The Associations request that PHMSA take the same approach.

The Associations recommend the following revisions to § 190.211(h) and 190.213(a):

> **§ 190.211 Hearing.**
>
> (h) ***Preparation of decision.*** After consideration of the case file, the Presiding Official prepares a recommended decision in the case, which is then forwarded to the Associate Administrator for issuance of a final order. The Presiding Official will simultaneously provide a copy of the recommended decision to the Respondent and OPS.
>
> **§ 190.213 Final order.**
>
> (a) In an enforcement proceeding commenced under § 190.207, an attorney from the Office of Chief Counsel prepares a recommended decision after expiration of the 30-day response period prescribed in § 190.208. If a hearing is held, the Presiding Official prepares the recommended decision as set forth in § 190.211. The recommended decision is forwarded to the Associate Administrator who considers the case file and issues a final order. The recommended decision will be forwarded to the Respondent at the same time as it is distributed to the Associate Administrator.

h. Modifications to the Settlement Process

PHMSA is required to allow respondents to request the use of a consent agreement,[52] which helps to allow safety issues to be resolved in an expeditious and efficient manner. Settlements allow both PHMSA and the operator to conserve time and resources that are typically expended in adjudicating a matter through a hearing.

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[50] *See Goldberg v. Kelly, 397 U.S. 254, 271 (1970) (*holding that "the decisionmaker's conclusion as to a recipient's eligibility must rest solely on the legal rules and evidence adduced at the hearing.")

[51] 49 C.F.R. § 209.323 through 327 (FRA regulations consider an initial decision, finality of decision, and appeal process); 49 C.F.R. § 13.232 (FAA's regulations outlining the requirements for the issuance of an initial decision at the conclusion of a hearing); 40 C.F.R. § 22.27(c) (EPA regulations contemplate an initial decision, a motion to reopen a hearing, and an appeal process); 29 C.F.R. § 38.112 (DOL regulations provide procedures for an initial decision and final decision); 21 C.F.R. Part 12, Subpart G (FDA's procedures initial and final decisions).

[52] 49 U.S.C. § 60117(b)(1)(A).

The Associations have identified three modifications that will further expedite the settlement process: (1) amendments to Part 190 to allow for settlements beyond Notices of Probable Violation and Proposed Safety Orders; (2) a recognition that alleged violations that are settled and not adjudicated should not be included as part of the prior history for subsequent civil penalty calculations, and (3) a policy noting that an operator does not need to admit to a violation in order to resolve a case via a consent agreement.

Historically, PHMSA has included items from a settlement agreement as violations in an operator's prior history for civil penalty calculation purposes. Given that in the context of a settlement there is no demonstration that any violation actually occurred, the operator should not be penalized for agreeing to resolve the matter via a consent agreement. A respondent's history of prior offenses is a factor PHMSA uses in determining future civil penalties.[53] In addition, while some operators have entered into consent agreements with the Agency without admitting to a violation, PHMSA has mandated in other cases that the alleged violation is treated as a violation as part of a consent agreement. This approach defeats the purpose of a compromise and is contrary to the DOT General Counsel's Memo on fairness in the enforcement process.[54]

The Associations recommend the following modifications to § 190.219(b):

§ 190.219(b) Consent order.

A consent order executed under paragraph (a) of this section shall include:
(1) An admission by the respondent of all jurisdictional facts;
(2) An express waiver of further procedural steps and of all right to seek judicial review or otherwise challenge or contest the validity of that order;
(3) An acknowledgement that the notice of probable violation (or other enforcement notice) may be used to construe the terms of the consent order; ~~and~~
(4) A statement of the actions required of the respondent and the time by which such actions shall be accomplished; and
(5) Any probable violations that are resolved through a consent agreement must not be included in a respondent's prior history for calculation of proposed civil penalties in 190.225.

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[53] 49 C.F.R. §190.225.
[54] DOT General Counsel Enforcement Memo, at 9-10 ("Where applicable statutes vest the agency with discretion with regard to the amount or type of penalty sought or imposed, the penalty should reflect due regard for fairness, the scale of the violation, the violator's knowledge and intent, and any mitigating factors (such as whether the violator is a small business).")

For purposes of settlement, a respondent is not required to admit to the existence of a violation.

i. Petitions for Reconsideration

The Associations seek modifications to section 190.243(c) to remove undue burdens. Section 190.243(c) provides that the filing of a petition for reconsideration will stay the payment of any assessed civil penalty, but not any required corrective actions (unless the Associate Administrator grants a stay request).[55] PHMSA does not often grant requests to stay the terms of a compliance order. While the Associations understand that there may be specific situations where the terms of a compliance order should be implemented as soon as possible to mitigate a potential safety risk, the vast majority of compliance orders could be stayed to allow for a complete and fair adjudication. Often, operators are forced to complete the terms of the compliance order prior to a decision on the petition for reconsideration which ultimately makes the petition moot.

The Associations request that PHMSA modify section 190.243(c) to note that the filing of a petition also stays a compliance order unless the Administrator provides otherwise. This approach would allow for flexibility if the Administrator were to have concerns in a specific case. This modification would eliminate inefficiencies and ensure fairness and due process.

The Associations recommend the following revisions to § 190.243(c):

§ 190.243 Petitions for reconsideration.

(c) The filing of a petition under this section stays the payment of any civil penalty assessed. It also stays any required corrective action subject to the petition, unless the Associate Administrator otherwise determines that a stay would jeopardize pipeline safety . ~~. However, unless the Associate Administrator otherwise provides, the order, including any required corrective action, is not stayed.~~

j. Safety Orders

PHMSA's Freedom of Information Act (FOIA) office is often reluctant to categorize emails exchanged during a safety order consultation process as confidential settlement and deliberative materials that are protected from FOIA requests. The pipeline safety regulations already acknowledge that information exchanged during these consultations cannot be used as admissions if the matter proceeds to hearing. Communications exchanged during the consultation process should not be subject to public disclosure, as these communications help

[55] 49 C.F.R. § 190.243(c).

to efficiently resolve potential issues that do not require initiation of a formal proceeding. Potential disclosure could damper these informal communications and lead to unnecessary proceedings. The Associations request that PHMSA consider the following revisions to section 190.239(b)(2):

> **§ 190.239 Safety orders.**
>
> **(b)** ***How is an operator notified of the proposed issuance of a safety order and what are its response options?***
> **(2)** ***Informal consultation.*** Upon timely request by the operator, PHMSA will provide an opportunity for informal consultation concerning the proposed safety order. Such informal consultation shall commence within 30 days, provided that PHMSA may extend this time by request or otherwise for good cause. Informal consultation provides an opportunity for the respondent to explain the circumstances associated with the risk condition(s) identified in the notice and, where appropriate, to present a proposal for corrective action, without prejudice to the operator's position in any subsequent hearing. If the respondent and Regional Director agree within 30 days of the informal consultation on a plan for the operator to address each risk condition, they may enter into a written consent agreement and the Associate Administrator may issue a consent order incorporating the terms of the agreement. If a consent agreement is reached, no further hearing will be provided in the matter and any pending hearing request will be considered withdrawn. If a consent agreement is not reached within 30 days of the informal consultation (or if informal consultation is not requested), the Associate Administrator may proceed under paragraphs (b)(3) through (5) of this section. If PHMSA subsequently determines that an operator has failed to comply with the terms of a consent order, PHMSA may obtain any administrative or judicial remedies available under 49 U.S.C. 60101 et seq. and this part. If a consent agreement is not reached, any admissions made by the operator during the informal consultation shall be excluded from the record in any subsequent hearing. Nothing in this paragraph (b) precludes PHMSA from terminating the informal consultation process if it has reason to believe that the operator is not engaging in good faith discussions or otherwise concludes that further consultation would not be productive or in the public interest. All correspondence exchanged during an informal consultation will be treated as a settlement communication.

k. Inclusion of Statutory Requirements in the Pipeline Safety Regulations

The Associations have identified several sections of the Pipeline Safety Act that have not been codified. Clarifying the regulations will reduce uncertainty and governmental inefficiency.

i. Response options

Section 60117(b)(1)(B) provides that PHMSA must "allow the respondent and the agency to convene 1 or more meetings—(i) for settlement or simplification of the issues; or (ii) to aid in the disposition of issues." Although Section 108 of the PIPES Act was self-executing, PHMSA should codify these provisions in Part 190. PHMSA currently acknowledges this right in its Enforcement Manual,[56] but not yet in Part 190.

The Associations recommend adding the following provision to § 190.208:

> **§ 190.208(f) Response options.**
>
> (f) If requested by respondent, OPS must convene one or more meetings for settlement or simplification of the issues, or to aid in the disposition of issues.

The Associations also urge PHMSA to amend section 190.208 to require the Regional Director to provide the violation report and civil penalty worksheet contemporaneously with a Notice of Probable Violation when it is issued. Currently, section 190.208(c) provides that a respondent may request a copy of the violation report.[57] Similarly, PHMSA issued guidance in 2016 stating that the civil penalty worksheet would be provided upon request to respondent.[58] The simultaneous issuance of the Notice of Probable Violation, the violation report, and the civil penalty worksheet is appropriate and fair and prevents unnecessary delays consistent with the directive in the DOT General Counsel Enforcement Memo. The Associations request that PHMSA update its Enforcement Manual to address this issue and then amend section 190.208(c), as follows:

> **§ 190.208(c) Response options**
>
> (c) ~~Before or after responding in accordance with paragraph (a) of this section or, when applicable paragraph (b) of this section, the respondent may request a copy of the violation report from the Regional Director as set forth in § 190.209. The Regional Director will provide the violation report to the respondent within five business days of receiving a request.~~ The Regional Director must provide the violation report and civil penalty calculations (if appropriate) to the Respondent concurrently with the Notice referenced in paragraph (a) and (b) of this section. The civil penalty calculations cannot be hidden or inaccessible in any way.

ii. Definition of Case File

[56] OPS Pipeline Safety Enforcement Procedures - Section 4, Section 4.2.5 (Dec. 5, 2024).
[57] 49 C.F.R. § 190.208(c).
[58] Pipeline Safety: General Policy Statement; Civil Penalties 81 Fed. Reg. 71,566 (Oct. 17, 2016).

In 2020, Congress mandated that the case file of an enforcement proceeding include "all agency records pertinent to the matters of fact and law asserted."[59] PHMSA has never codified this definition. On May 29, 2025, PHMSA's Chief Counsel acknowledged that the Agency had not addressed the implementation of this congressional mandate and advised OPS to revise its procedures.[60] As a result of that memo, the Associations recommend the following changes to sections 190.209(a) and 190.212(c) to include the presiding official's authority to compel records and issue subpoenas on behalf of either OPS or the respondent:

> **§ 190.209(a) Case file**
>
> (a) The case file, as defined in this section, must include all agency records pertinent to the matters of fact and law asserted and is available to the respondent in all enforcement proceedings conducted under this subpart.
>
> **§ 190.212(c) Presiding official, powers, and duties.**
>
> (c) ***Powers and duties of Presiding Official*.** The Presiding Official will conduct a fair and impartial hearing and take all action necessary to avoid delay in the disposition of the proceeding and maintain order. The Presiding Official has all powers necessary to achieve those ends, including, but not limited to the power to:
> (1) Regulate the course of the hearing and conduct of the parties and their counsel;
> (2) Receive evidence and inquire into the relevant and material facts;
> (3) Require the submission of documents and other information including the authority to compel OPS to provide all agency records pertinent to the matters of fact and law asserted;
> (4) Issue a subpoena on behalf of OPS and/or respondent as set forth in § 190.7;
> (5) Direct that documents or briefs relate to issues raised during the course of the hearing;
> (6) Set the date for filing documents, briefs, and other items;
> (7) Prepare a recommended decision; and
> (8) Exercise the authority necessary to carry out the responsibilities of the Presiding Official under this subpart.

iii. Reply to Region's Post-Hearing Submission

Section 60117(b)(1)(D) requires PHMSA to "allow the respondent to reply to each post-hearing submission of the agency."[61] PHMSA has acknowledged this statutory provision in its

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[59] 49 U.S.C. § 60117(b)(1)(C).
[60] PHMSA Chief Counsel Memo - Revised Procedures for Determining the Contents of the Case File in Pipeline Safety Enforcement Proceedings (May 29, 2025), at 1.
[61] 49 U.S.C. § 60117(b)(1)(D).

Enforcement Manual,[62] but has not yet codified it into the regulations. The Associations recommend the following amendments to section 190.211(g).

§ 190.211 Hearing.

(g) ***Post-hearing submission***. The respondent and OPS may request an opportunity to submit further written material after the hearing for inclusion in the record. The Respondent may reply to each post-hearing submission of the agency. The Presiding Official will allow a reasonable time for the submission of the material and will specify the submission date. If the material is not submitted within the time prescribed, the case will proceed to final action without the material.

iv. Consent orders

Section 60117(b)(1)(A) directs PHMSA to "allow the respondent to request the use of a consent agreement and consent order to resolve any matter of fact or law asserted."[63] Notably, this ability to resolve any matter of fact or law with a consent agreement and order is not limited by enforcement case type. However, PHMSA has not updated its regulations to reflect this statutory amendment.[64] Section 190.219 is limited to compliance orders, corrective action orders, and safety orders. The Associations recommend revising section 190.219(a) as follows:

§ 190.219 Consent order.

(a) At any time prior to the issuance of a final order under 190.213 or an order directing amendment pursuant to 190.206(b) ~~compliance order under § 190.217~~, a corrective action order under § 190.233, or a safety order under § 190.239, the Regional Director and the respondent may agree to resolve the case by execution of a consent agreement and order, which may be jointly executed by the parties and issued by the Associate Administrator. Upon execution, the consent order is considered a final order under § 190.213.

v. Petition for Declaratory Order

Section 60117(b)(1)(J) requires the Agency to "allow an operator to request that an issue of controversy or uncertainty be addressed through a declaratory order in accordance with section

[62] Enforcement Manual, Section 4.1.7.5.
[63] 49 U.S.C. § 60117(b)(1)(A).
[64] 49 C.F.R. § 190.219(a) states "[a]t any time prior to the issuance of a compliance order under § 190.217, a corrective action order under § 190.233, or a safety order under § 190.239, the Regional Director and the respond may agree to resolve the case by execution of a consent agreement and order, which may be jointly executed by the parties and issued by the Associate Administrator."

554(e) of title 5."[65] Declaratory orders are considered final agency action and are a useful and necessary tool for enforcement agencies. Yet, PHMSA states in its Enforcement Manual that "if an operator requests a declaratory order under 5 U.S.C. § 554(e), PHMSA will refer the operator to submit a request for written interpretation."[66] PHMSA then references section 190.11(b).[67] A declaratory order is final agency action. It is not an interpretation. Since the PIPES Act of 2020 became law, PHMSA has received petitions for declaratory order and set out a process for notice and comment.[68] PHMSA should remove footnote 8 in its Enforcement Manual and add section 190.12 to codify this useful tool. The petition for declaratory order provides an efficient process to allow greater regulatory certainty to the regulated community. The Associations recommend that the Agency add the following text to Part 190:

§ 190.12 Petitions for Declaratory Order.

(a) An operator may request that an issue of controversy or uncertainty be addressed through a declaratory order in accordance with section 554(e) of title 5. Petitions for a declaratory order must be published in the Federal Register for notice and comment.

vi. Request for Protection of Confidential Commercial Information

PHMSA requires operators to submit two copies (original plus redacted) when seeking protection of confidential commercial information.[69] This approach is resource intensive and unnecessary. Operators should be allowed to mark certain documents with the relevant FOIA markings. If the document is subject to a subsequent FOIA request, then PHMSA is obligated to consult with the operator. At that time, the operator can provide redacted documents. Such a process would be more efficient and save needless use of resources by the regulated community. The Associations recommend the following amendments to section 190.343:

§ 190.343 Information made available to the public and request for protection of confidential commercial information.

[65] 49 U.S.C. § 60117(b)(1)(J).
[66] OPS Pipeline Safety Enforcement Procedures - Section 4 (Dec. 5, 2024) (Enforcement Manual), at 34, fn. 8.
[67] *Id.*
[68] *See Pipeline Safety: Mifflin Energy Corporation's Petition for Declaratory Order Concerning Part 192 Jurisdiction and Operator Responsibility over Customer-Owned Piping*, https://www.regulations.gov/document/PHMSA-2023-0080-0002 (Nov. 9, 2023).
[69] 49 C.F.R. § 190.343(a)(2).

Asking for protection of confidential commercial information. You may ask us to give confidential treatment to information you give to the agency by taking the following steps:
(1) Mark "confidential" on each page of the original document you would like to keep confidential.
~~(2) Send us, along with the original document, a second copy of the original document with the confidential commercial information deleted.~~
(~~3~~ 2) Explain why the information you are submitting is confidential commercial information

2. Interpretations[70]

While PHMSA requested feedback on interpretations that should be incorporated into the regulations, the Associations have also identified interpretations that should be rescinded.

a. Corrosion of or Along a Longitudinal Seam Weld

The Associations request that PHMSA rescind its 2017 interpretation covering section 195.452(h)(4)(iii)(H) (Corrosion of or along a longitudinal seam weld).[71] In that interpretation, PHMSA evaluated the scope of the 180-day evaluation and remediation requirement and determined that the regulation requires repair of any corrosion of or along the long seam, even clearly non-injurious corrosion.[72] This interpretation has resulted in thousands of unnecessary excavations to address non-injurious corrosion anomalies. The Associations discussed the costs of those efforts and proposed alternative criteria for long seam weld corrosion that is focused on actual safety risk in its comments to the Repair Criteria ANPRM.[73] The Associations continue to urge PHMSA to rescind this interpretation.

The Associations also request that PHMSA reinstate FAQ 7.16, revision date December 6, 2002 regarding this topic as a temporary measure.

The requirement on 195.452(h)(4)(iii)(H) addresses corrosion "of or along" a longitudinal seam. Such conditions would indicate corrosive attack specifically affecting the longitudinal seam and which therefore could have significant impact on pipe integrity.

A pipeline operator must consider the type of corrosion anomaly indicated as well as the age of their pipe and type of seam and be able to demonstrate that detected corrosion does not

[70] This section is in response to ANPRM Question # A.7.
[71] PHMSA Letter of Interpretation to Plains All-American GP LLC, PI-17-0014 (Apr. 26, 2018).
[72] *Id.*
[73] Comments from API, LEPA, GPA Midstream Association, and AFPM, https://www.regulations.gov/document/PHMSA-2025-0019-0021 (July 21, 2025).

affect the seam to any greater extent than the pipe body if corrosion near a longitudinal seam is not to be repaired under this criterion.

b. Breakout Tanks and the Meaning of Buried

The Associations request that PHMSA rescind the 2022 interpretation as applied to breakout tanks.[74] In section 195.553, the Agency provides that "buried means covered or in contact with soil."[75] In a 2022 interpretation,[76] the Agency concluded that if a breakout tank is in contact with any type of soil, the operator would need to comply with cathodic protection requirements pursuant to 49 CFR § 195.563(a)[77] and if it is not in contact with soil, it would need to comply with the atmospheric corrosion control requirements in § 195.583.[78] This is not a workable solution for operators with double-bottom tanks. The Associations seek a rescission of this interpretation and modifications to sections 195.563 and 195.565.

c. Definition of a Navigable Waterway

In PI-73-037, the Office of Pipeline Safety took a broad view of the definition of a navigable waterway as applied in section 195.412.[79] At the time, the Agency defined navigable waters as "those waterways which have been designated as being navigable by Part 2 of Title 33 of the Code of Federal Regulations."[80] In 2001, PHMSA stated in an interpretation that the Agency would rely on the National Waterways Network (NWN) to identify commercially navigable waterways.[81] The use of the NWN database replaced the reliance on the USCG designation. In 2017, PHMSA continued to reference the NWN database in its Part 195 enforcement guidance.[82] In 2015, PHMSA supported the 2001 interpretation and subsequent enforcement guidance and discounted the 1973 interpretation.[83] Yet, the 1973 interpretation is still listed as valid on PHMSA's website. The Associations request that PHMSA rescind the 1973 interpretation.

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[74] PHMSA Letter of Interpretation to Manatt, Phelps, and Phillips, LLP (representing Chemoil), PI-20-0014 (Oct. 7, 2021).
[75] 49 C.F.R. § 195.553.
[76] PHMSA Letter of Interpretation to Manatt, Phelps, and Phillips, LLP (representing Chemoil), PI-20-0014 (Oct. 7, 2021).
[77] *Id.*
[78] *Id.*
[79] PHMSA Letter of Interpretation to Colonial Pipeline Company, PI-73-037 (Nov. 16, 1973).
[80] *Id.*
[81] PHMSA Letter of Interpretation to Marathon Ashland Pipeline, PI-01-0100 (Jan. 29, 2001)(citing 65 Fed. Reg. 54,440).
[82] PHMSA Operations and Maintenance Enforcement Guidance, Part 195 Subpart F at 51-56.
[83] *In the Matter of Alyeska Pipeline Service Co.,* CPF No. 5-2025-5015 (Nov. 22, 2015) at 5.

3. Emergency Response

a. Response Plans for Onshore Oil Pipelines

PHMSA did not request specific comments in response to Part 194, however, the Associations have identified several areas where modifications would reduce undue burdens and eliminate inefficiencies.

b. Electronic Retention of Response Plan

The Associations recommend modifying section 194.111 which requires an operator to maintain the relevant portions of the response plan at the operator's headquarters and at other locations where response activities may be conducted. The regulation also requires the operator provide a copy to each qualified individual. The technology available today is vastly different from the technology available when the regulation was first written in the early 1990s. Paper copies can cost between $600-$900 each and are obsolete the moment they are printed. Other types of electronic media are also outdated such as laptop computers with CD-ROM readers.

PHMSA should modify section 194.111 to allow for electronic copies of response plans, or the "relevant portions" of those plans to substitute for paper copies. Applications exist today that can turn today's phones and devices into plan storage and response checklists with more capabilities than a paper document. Allowing electronic storage and access would nullify the need for copies to be kept in vehicles or trailers. It could also increase security protections of these critical documents.

The Associations recommend the following changes:

> **§ 194.111 Response plan retention.**
>
> (a) Each operator shall maintain relevant portions of its response plan either at the operator's headquarters and at other locations from which response activities may be conducted, for example, in field offices, supervisors' vehicles, or spill response trailers or electronically on a secured handheld device.
>
> (b) Each operator shall provide a copy of its response plan to each qualified individual.

c. Centralized Approval Process

PHMSA should clarify that the review and approval conducted at the Office of Pipeline Safety in Washington, D.C. is the official approval process for emergency response plans. Section 194.119 provides that operators must submit two copies of each response plan to PHMSA's headquarters in Washington, D.C. for review and approval.[84] The Associations' members report that once PHMSA's headquarters staff has completed its review and approve an emergency response plan, the region then requests further modifications during field audits. This approach creates inefficiencies and unnecessary confusion. Field audits should be used to validate the plan, not request modifications. Emergency response plans should be reviewed and approved by a single, consistent source.

§ 194.119 Submission and approval procedures.

(d) For response zones of pipelines described in § 194.103(c) OPS's Preparedness, Emergency Support, and Security Division will approve the response plan if OPS determines that the response plan meets all requirements of this part. OPS may consult with the U.S. Environmental Protection Agency (EPA) or the U.S. Coast Guard (USCG) if a Federal on-scene coordinator (FOSC) has concerns about the operator's ability to respond to a worst case discharge.

4. Corrosion Control[85]

a. Coating Material

Section 195.559(c) provides that coating material must meet certain requirements including "be sufficiently ductile to resist cracking."[86] This requirement does not add any value. If coating cracks were to occur, the operator would need to repair them pursuant to section 195.561. The language in section 195.559(c) is therefore redundant and unnecessary. The Associations recommend the following change:

§ 195.559 What coating material may I use for external corrosion control?

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;

(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

~~(c) Be sufficient ductile to resist cracking.~~

(d) Have enough strength to resist damage due to handling and soil stress;

(e) Support any supplemental cathodic protection; and

(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

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[84] 49 C.F.R. § 194.119.
[85] This section is in response to ANPRM Question # B.6.
[86] 49 C.F.R. § 195.559(c).

b. External Corrosion Control

In section 195.573(a)(1), the Associations urge PHMSA to consider a longer corrosion testing interval when in-line inspection (ILI) data is used to evaluate for external corrosion.

The Associations recommend the following revisions:

§ 195.573 What must I do to monitor external corrosion control?

(a) ***Protected pipelines.*** You must do the following to determine whether cathodic protection required by this subpart complies with § 195.571:

(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if either provision in (i) or (ii) apply ~~tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines~~, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

(i) separately protected short sections of bare or ineffectively coated pipelines; or (ii) pipeline is managed with a risk based integrity management program, where in-line inspection of the pipeline is performed every 5 calendar years, but with intervals not exceeding 68 months and it evaluates for external corrosion.

In section 195.573(c), PHMSA should allow remote monitoring of corrosion rectifiers while still requiring annual visits. This change would align Part 195 with the current gas pipeline requirement.

The Associations recommend the following revisions:

§ 195.573 What must I do to monitor external corrosion control?

(c) ***Rectifiers and other devices.*** You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	Check frequency
Rectifier Reverse current switch Diode Interference bond whose failure would jeopardize structural protection	~~At least six times each calendar year, but with intervals not exceeding 2½ months.~~

Device	Check frequency
Other interference bond	At least once each calendar year, but with intervals not exceeding 15 months.

(1) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months between inspections. This may be done either through remote measurement or through an onsite inspection of the rectifier.
(2) Each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.

c. Atmospheric Corrosion Control

For atmospheric corrosion control, the Associations recommend eliminating the reference to "suitable" coating material. This term is undefined, vague, and does not add value beyond the other corrosion control requirements. It allows for a broad range of interpretations from inspectors that can lead to findings of non-compliance when a pipeline is properly protected.

The Associations recommend the following revisions:

§ 195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?

(a) You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (b) of this section.

~~(b) Coating material must be suitable for the prevention of atmospheric corrosion.~~

(~~c~~b) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

PHMSA should also replace prescriptive intervals for atmospheric corrosion inspection with a risk-based assessment that better reflects the infrequency of such issues.

Additionally, PHMSA should also clarify the applicability of atmospheric corrosion control requirements under §195.583 as it applies to breakout tanks. These requirements are intended for portions of above-ground facilities that are exposed to the atmosphere and can be visually inspected. However, the bottom of a breakout tank that rests on a concrete or asphalt foundation, or that includes a double-bottom configuration, is not exposed to the atmosphere; it is enclosed, shielded from environmental elements, and inaccessible for visual inspection. Therefore, it does not meet the criteria for atmospheric exposure and should not be subject to §195.583. Proposed revisions to §195.583 are provided below.

The Associations recommend the following revisions:

§ 195.583 What must I do to monitor atmospheric corrosion control?

(a) Except as provided by paragraph (e) of this section, you must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion as follows:, as follows:

If the pipeline is located:	**Then the frequency of inspection is:**
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by § 195.581.

(d) Operators may implement a risk-based assessment methodology to determine inspection priorities for aboveground pipeline segments exposed to the atmosphere. Segments located in environments with limited exposure to corrosive conditions—such as dry climates, protective enclosures, or those with effective coatings—may be subject to extended inspection intervals or excluded from routine atmospheric corrosion inspection. Justification must be documented, supported by historical performance, environmental factors, and engineering judgment.

(e) Breakout tank bottoms are exempt from this requirement if—

(1) Resting on concrete, asphalt, or non-conductive foundations:

(2) Enclosed within double-bottom configuration; or

(3) Shielded by structural components that prevent atmospheric exposure.

d. Stress Corrosion Cracking

The Associations also recommend removing outdated testing requirements for stress corrosion cracking. PHMSA should remove the requirement for high pressure hydrotest with spike test, which is potentially damaging to pipes and no longer necessary with modern ILI technology and engineering assessment capabilities.

§ 195. What standards apply to direct assessment?

(c) If you use direct assessment on an onshore pipeline to evaluate the effects of stress corrosion cracking, you must develop and follow a Stress Corrosion Cracking Direct Assessment plan that meets all requirements and recommendations of NACE SP0204 (incorporated by reference, *see* § 195.3) and that implements all four steps of the Stress Corrosion Cracking Direct Assessment process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204, Section 1.1.7, Stress Corrosion Cracking Direct Assessment is complementary with other inspection methods such as in-line inspection or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for….

(4) ***Remediation and mitigation.*** If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Non-significant SCC, as defined by NACE SP0204, may be mitigated ~~by either hydrostatic testing~~ in accordance with paragraph (b)(4)(ii) of this section, or by grinding out with verification by Non-Destructive Examination (NDE) methods that the SCC defect is removed and repairing the pipe. If grinding is used for repair, the remaining strength of the pipe at the repair location must be determined using ~~ASME/ANSI B31G or RSTRENG (incorporated by reference, *see* § 195.3)~~ an appropriate calculation method included in § 195.452(h)(1)(i) and must be sufficient to meet the design requirements of subpart C of this part.

(ii) Significant SCC must be mitigated using a hydrostatic testing program ~~with a minimum test pressure between 100% up to 110% of the specified minimum yield strength for a 30-minute spike test immediately followed by a pressure test in accordance with~~ or a combination of adequate repair of the as-found significant SCC and followed up with an ILI program that is capable of detecting SCC. If a hydrostatic test is selected, the test approach, including spike test or normal hydrotest, and test pressure should be adequately designed by the operator to maintain the integrity of the pipeline before the next reassessment. The hydrotest should satisfy all requirements in subpart E of this part. ~~The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with subpart E of this part. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment retested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (c)(4)(i) of this section.~~ Alternatively, the significant SCC may be repaired in accordance with § 195.422 and followed up with ILI that is capable of detecting SCC.

5. Pressure Testing[87]

The Associations have reviewed the pressure testing requirements in Part 195, Subpart E and seek amendments in certain areas to reduce undue burdens. First, the Associations recommend amending section 195.304 to add flexibility on pressure testing low SMYS pipes. Operators need alternatives to test low stress pipe because a high-pressure hydrostatic test, can damage pipes.

The Associations recommend the following revisions:

§ 195.304 Test pressure.

(a) Unless otherwise permitted by paragraph (b) of this section, ~~T~~the test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during the test, for at least an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

(b) Each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS may be tested in accordance with the following:

(1) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

[87] This section is in response to ANPRM Question # B.6.

(2) Hydrocarbon liquid that does not vaporize rapidly may be used as a test medium at the existing pressure of the connecting system.

(3) The line must be walked to check for leaks while the pressure is held for at least 1 hour.

Second, the Associations recommend adding new subsection (c) to section 195.304 to provide flexibility to conduct pressure tests at controlled facilities differently than for field pressure tests.

§ 195.304 Test pressure.

(c) For tests being performed within climate-controlled facilities, each pressure test must be maintained for at least 1 continuous hour at a pressure equal to 125 percent, or more, of the maximum operating pressure. Immediately after the pressure test, the piping shall be visually inspected for leaks at a pressure equal to 110 percent, or more, of the maximum operating pressure.

The Associations also recommend adding flexibility from small tubing pressure testing that is impracticable or increases risk to the system.

§ 195.305 Testing of components.

(a) Each pressure test under § 195.302 must test all ~~pipe and attached fittings, including~~ components, unless otherwise permitted by paragraph (b) of this section.

(b) A single component~~, other than pipe,~~ that is replacing an existing item ~~the only item being replaced~~ or that is added to the pipeline system, need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either—

(1) The component was hydrostatically tested at the factory; or

(2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.

Finally, the Associations also recommend recognizing the difference in required records for hydrotesting a pipe and components versus atmospheric and pressurized breakout tanks. PHMSA requires atmospheric and pressurized breakout tanks to be designed and constructed according to specific industry codes and therefore recommends an additional section be added to recognize the difference in documentation requirements. To clarify the distinction between pressure testing records for pipelines vs. breakout tanks, the Associations recommend the following additional paragraph to § 195.310:

§ 195.310 Records

(c) The record required by paragraph (a) of this section for atmospheric and pressurized breakout tanks shall be in accordance with the requirements of API STD 650 Sections 7.3.6 and 7.3.7, ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 or Division II (incorporated by reference, see §195.3) respectively.

6. Operations & Maintenance[88]

a. Rupture Analysis Factors

The Associations recommend the elimination of the prescriptive list of specific factors in section 195.402(c)(5)(ii) which may or may not apply, to analyze post rupture. PHMSA should also reduce the prescriptive requirements for failure analysis timing and reporting. These changes would eliminate arbitrary timing requirements.

The Associations recommend the following changes:

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

(c) ***Maintenance and normal operations.*** The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations…

(5) Investigating and analyzing pipeline accidents and failures, including sending the failed pipe, component, or equipment for laboratory testing or examination where appropriate, to determine the cause(s) and contributing factors of the failure and to minimize the possibility of a recurrence.

(ii) ***Analysis of rupture and valve shut-offs; preventive and mitigative measures.*** If a failure or accident on an onshore hazardous liquid or carbon dioxide pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in § 195.2, or the closure of an alternative equivalent technology, the operator of the pipeline must also conduct a post-failure or post-accident analysis of all the factors that may have impacted the release volume and the consequences of the release, and identify and implement operations and maintenance measures to minimize the consequences of a future failure or accident. The analysis must include all relevant factors impacting the release volume and the consequences.~~, including, but not limited to, the following:~~

[88] This section is in response to ANPRM Question # B.7.

~~(A) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the release or failure event;~~

~~(B) Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;~~

~~(C) Actual response time from identifying a rupture following a notification of potential rupture, as defined at § 195.2, to initiation of mitigative actions and isolation of the segment, and the appropriateness and effectiveness of the mitigative actions taken;~~

~~(D) Location and timeliness of actuation of all RMVs or alternative equivalent technologies; and~~

~~(E) All other factors the operator deems appropriate.~~

~~(iii) ***Rupture post-failure and accident summary.*** If a failure or accident on an onshore hazardous liquid or carbon dioxide pipeline involves the identification of a rupture following a notification of potential rupture; the closure of an RMV, as those terms are defined in § 195.2; or the closure of an alternative equivalent technology, the operator must complete a summary of the post-failure or -accident review required by paragraph (c)(5)(ii) of this section within 90 days of the failure or accident. While the investigation is pending, the operator must conduct quarterly status reviews until the investigation is completed and a final post-failure or -accident review is prepared. The final post-failure or -accident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the operator's appropriate senior executive officer. An operator must keep, for the useful life of the pipeline, the final post-failure or -accident summary, all investigation and analysis documents used to prepare it, and records of lessons learned.~~

b. Effectiveness Reviews of Procedures

The Associations recommend removal of sections 195.402(c)(12), (c)(13), (d)(5), and (e)(9). Those regulations provide that an operator must periodically re-review work to determine effectiveness of procedures for normal operations, abnormal operations, and during emergencies. These obligations are duplicative of other provisions, are difficult to document, and generally add little value. For instance, due to operator qualification requirements for training and qualification, post-accident and incident reviews, and the requirements of API 1163 (continuous improvement), procedures are reviewed on a regular basis eliminating the overburdensome requirement for an effectiveness review.

c. Inconsistencies between sections 195.402 and 192.615

The emergency plan requirements in sections 195.402 and 192.615 reference definitions found in sections 195.2 and 192.3, which in turn reference the rupture identification requirements in 195.417 and 192.635. This layered and non-aligned structure results in conflicting requirements that complicate compliance. It also introduces ambiguity into emergency planning with rupture response.

According to § 195.402(e)(4), operators must take necessary actions—including emergency shutdown, valve closure, or pressure reduction—to minimize hazards. Operators must also develop written rupture identification procedures to evaluate and determine whether a notification of a potential rupture, as defined in § 195.2, is an actual rupture event or non-rupture event. These procedures must identify the sources of information and operational criteria used to make that determination. However, § 195.402(e)(7) does not allow for this analysis and instead requires operators to "immediately and directly notify the appropriate public safety answering point (911) after notification of a potential rupture has occurred, regardless of whether an actual rupture has been verified." The Associations recommend the following changes to Part 195:

> **§ 195.402 Procedural manual for operations, maintenance, and emergencies.**
>
> (e) ***Emergencies.*** The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs:
>
> (7) After confirmation of an actual rupture as provided in section 195.402(e)(4), ~~N~~notifying the appropriate public safety answering point (*i.e.,* 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of hazardous liquid or carbon dioxide pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency, and any additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid (HVL). The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdiction(s) in which the pipeline is located after notification of potential rupture, as defined at § 195.2, has occurred to coordinate and share information to determine the location of the release, regardless of whether the segment is subject to the requirements of § 195.258 (c) or (d), § 195.418, or § 195.419.

d. Emergency Response Training

The Associations seek changes to the timeframe in section 195.403(b) to verify that personnel have met the objectives of the emergency response training program and making any appropriate changes. PHMSA currently requires operators to complete this review and make any changes at least once each calendar year but at intervals not exceeding 15 months.[89] Keeping track of the end date of this interval deadline is burdensome and can create inefficiencies as operators manage multiple compliance dates, scheduling and logistics, and documentation. Switching to a uniform deadline will reduce the administrative burdens of tracking when various intervals expire. This simplified approach will reduce burdens yet retain the safety objective of ensuring personnel performance continues to be effective. Without having to track various deadlines across multiple programs, operators can re-allocate resources towards program enhancements, collaboration, and overall operational performance.

The Associations recommend the following changes:

> **§ 195.403 Emergency response training.**
>
> (b) ~~At the intervals not exceeding 15 months, but~~ At least once each calendar year, each operator shall:
>
> (1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section; and
> (2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective.

e. Materials[90]

The Associations urge PHMSA to modify section 195.112 to allow operators to use advanced pipe materials and design approaches. Section 195.112 requires that any new pipe must be made of "steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system."[91] PHMSA regulations currently do not allow operators of hazardous liquids pipelines to construct pipeline facilities out of non-steel materials, absent cumbersome and infrequently granted individual authorizations.[92] In 1981, PHMSA's predecessors set up a process for an operator to notify the Agency of its intent to use material other than steel prior to the commencement of service.[93] If the Secretary determined that the use of the non-steel material would be "unduly hazardous," the Agency could order the operator not to transport hazardous liquid in that manner until further notice.[94] This approach may have been appropriate when these regulations were first developed decades ago, but, since then, non-steel pipeline materials have been rigorously tested for use in liquids pipeline service. These materials are corrosion

[89] 49 C.F.R. § 195.403(b).
[90] This section is in response to ANPRM Question # B.6.
[91] 49 C.F.R. § 195.112(a).
[92] 49 C.F.R. § 195.8. *See* PHMSA Letter of Interpretation to H.L. Crawford, Jr. of Mid-Continent Pipe Line Co., PI-89-020 (Sept. 19, 1989).
[93] 49 C.F.R. § 195.8; *See also,* Transportation of Liquids by Pipeline, 46 Fed. Reg. 38,357 (July 27, 1981).
[94] 49 C.F.R. § 195.8.

resistant, strong, and their safety performance has been proven in unregulated liquid service and in specially authorized regulated applications. Consideration of allowing non-steel materials as transmission pipelines is also warranted as new sources of fuels and other commodities that may be transported by pipeline emerge.

This comment is also responsive to PHMSA's request for stakeholders to identify undue burdens. Allowing the use of non-steel pipe in hazardous liquid service will reduce costs and expedite the construction process while maintaining safety.

The Associations request that PHMSA remove sections 195.8 and modify 195.112(a) to expressly allow the use of non-steel pipe in liquid service.

> **~~§ 195.8 Transportation of hazardous liquid or carbon dioxide in pipelines constructed with other than steel pipe.~~**
>
> ~~No person may transport any hazardous liquid or carbon dioxide through a pipe that is constructed after October 1, 1970, for hazardous liquids or after July 12, 1991 for carbon dioxide of material other than steel unless the person has notified the Administrator in writing at least 90 days before the transportation is to begin. The notice must state whether carbon dioxide or a hazardous liquid is to be transported and the chemical name, common name, properties and characteristics of the hazardous liquid to be transported and the material used in construction of the pipeline. If the Administrator determines that the transportation of the hazardous liquid or carbon dioxide in the manner proposed would be unduly hazardous, he will, within 90 days after receipt of the notice, order the person that gave the notice, in writing, not to transport the hazardous liquid or carbon dioxide in the proposed manner until further notice.~~
>
> **§ 195.112 New pipe.**
>
> Any new pipe installed in a pipeline system must comply with the following:
>
> (a) The pipe must be ~~made of steel of the carbon, low alloy-high strength, or alloy type that is~~ able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system.
>
> (b) The pipe must be made in accordance with a written pipe specification that sets forth the chemical requirements for the pipe material and mechanical tests for the pipe to provide pipe suitable for the use intended.
>
> (c) Each length of pipe with a nominal outside diameter of 4½ in (114.3 mm) or more must be marked on the pipe or pipe coating with the specification to which it was made, the specified minimum yield strength or grade, and the pipe size. The

marking must be applied in a manner that does not damage the pipe or pipe coating and must remain visible until the pipe is installed.

f. Design[95]

The Associations recommend revisions to section 195.101 to increase the working temperature. This modification would accommodate increasingly prevalent warmer temperatures. The Associations provide the following suggestions to the regulatory text:

§ 195.101 Qualifying metallic components other than pipe.

Notwithstanding any requirement of the subpart which incorporates by reference an edition of a document listed in § 195.3, a metallic component other than pipe manufactured in accordance with any other edition of that document is qualified for use if—
(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component: and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in § 195.3:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings. Within the metal temperature limits of −20°F (−30°C) to 250°F (120°C), pressure ratings for components shall conform to those stated for 100°F(40°C) in their material standards and specifications listed in § 195.3. The nonmetallic trim, packing, seals , and gaskets shall be made of materials that are not injuriously affected by the fluid in the piping system and shall be capable of withstanding the pressures and temperatures to which they will be subjected in service. Consideration shall be given to possible conditions that may cause low temperatures on pipelines transporting liquids that become gases at or near atmospheric conditions.

g. Control Room Management[96]

i. Team Training

[95] This section is in response to ANPRM Question # B.6.
[96] This section is in response to ANPRM Question # B.7.

The Associations request that PHMSA reevaluate its team training requirements in section 195.446(h)(6). The current requirement provides that operators must have a controller training program that includes "[c]ontrol room team training and exercises that include both controllers and other individuals, defined by the operator, who *would reasonably be expected* to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations."[97] PHMSA should refocus the training on controllers and their immediate supervisors. The "would" language in the regulation is broad and can be misinterpreted. It also moves away from the original recommendation for a team training requirement. In 2012, the NTSB issued a recommendation to PHMSA to "[d]evelop requirements for team training of control center staff involved in pipeline operations similar to those used in other transportation modes."[98] Section 195.446(h)(6) goes beyond the recommendation by including the vague and ambiguous term "reasonably be expected to interact with controllers. The fact that PHMSA only requires one controller to attend team training[99] further demonstrates a shift away from the original intent of NTSB's recommendation, *i.e.,* that the training focus on control center staff. PHMSA should revise its section 195.446(h)(6) requirement to limit team training to control center staff including those with the authority to direct or supersede the specific technical actions of a controller.
The Associations recommend the following revisions:

§ 195.446 Control room management.

(h) ***Training.*** Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements…
(6) Control room team training ~~and exercises~~ that include both controllers and control center personnel and other immediate support personnel (Supervisors, SCADA, Leak Detection, etc.), as defined by the operator, for communications during abnormal and emergency situations.

This modification would reduce ambiguity by focusing the requirement on individuals who are actually expected to engage in direct operational collaboration with controllers, rather than those who merely might in a hypothetical scenario.

[97] 49 C.F.R. §446(h)(6)(emphasis added).
[98] NTSB Safety Recommendation, P-12-007 (July 25, 2012).
[99] Control Room Frequently Asking Questions, H.09 (Jan. 16, 2018).

The current language is open to broad interpretation and creates an undue burden for operators to include personnel who may interact with the control center occasionally but are not primary or routine collaborators during operational events. The Team Training requirement adds to an already robust set of training requirements. Team Training overlaps with other required training, i.e. Emergency Response Drills. This creates an unnecessary strain and burden on operators with regard to scheduling, logistics, travel and staffing of safety sensitive individuals who have hours of service restrictions. Time spent producing, organizing and updating records that may not be necessary but are collected out of unnecessary caution related to future audits or inspections. Depending on the size of the operator, these activities could amount to unnecessary costs of $25,000 - $150,000 per year.

ii. Internal Communications Plan and Manual Operation

Section 195.446(c)(3) provides that an operator must "test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months."[100] PHMSA's interpretation of the scope and meaning of this interpretation has varied and the Associations seek clarifications to avoid unnecessary confusion and inefficiencies. Even though FAQ C-09 clearly states that if an operator does not plan to continue operation in manual mode, the communication plan only needs to address the safe shutdown of the pipeline, PHMSA inspectors have interpreted this regulation to require that all operators must choose to operate manually when SCADA is lost.[101] The Agency should clarify that manual operation is not required and if an operator loses SCADA, an operator can shut down the pipeline.

The Associations recommend the following revisions:

> **§ 195.446 Control room management.**
>
> **(c)** ***Provide adequate information.*** Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following…
> (3) Test and verify an internal communication plan to provide adequate means for manual operation or shutdown of the pipeline safely at least once each calendar year, but at intervals not to exceed 15 months.

[100] 49 C.F.R. § 195.446(c)(3).
[101] Control Room Management Frequently Asked Questions, C.09 ("If an operator does not intend to continue operating the pipeline in the event of a catastrophic SCADA failure, then only procedures to safely perform a controlled shutdown and maintain and monitor pipeline integrity need to be in place").

7. Valves[102]

The Associations have collected feedback on the implementation of the valve rule in the years since it was finalized. Of note, the Associations seek revisions to the notification of potential rupture, the application of the 10% threshold, the inclusion of check valves, and modifications to valve maintenance requirements.

a. Valve Capabilities

In remote locations where backup-power sources are impractical or impossible to install, PHMSA should allow the use of a risk-based analysis to evaluate consequences and benefits. The Associations recommend the following:

> **§ 195.419 Valves monitoring and operational capabilities.** An RMV, as defined in § 195.2, or alternative equivalent technology, must be capable of being monitored or controlled by either remote or onsite personnel as follows…
>
> …
>
> ~~(3) Have a back-up power source to maintain supervisory control and data acquisition (SCADA) systems or other remote communications for remote-control valve (RCV) or ASV operational status or be monitored and controlled by on-site personnel.~~

b. Valve Maintenance

PHMSA should align Part 195 valve maintenance requirements with current Part 192 regulations. PHMSA should delete unnecessary detail and allow the inspection schedule to run off of maintenance records, age, risk, and other relevant factors.

PHMSA should make the following changes:

> **§ 195.420 Valve maintenance.**
>
> (a) Each valve that might be required to operate during an emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year. Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

[102] This section is in response to ANPRM Question # B.7.

(b) Each operator must, at least ~~twice~~ once each calendar year, but at intervals not exceeding ~~7½~~ 15 months, inspect each mainline block valve to determine that it is functioning properly. Each rupture-mitigation valve (RMV), as defined in § 195.2 and not contained in a gathering line, or alternative equivalent technology (except check valves) that is installed under § 195.258(c) or § 195.418, must also be partially operated. Operators are not required to close the valve fully during the inspection; a minimum 25 percent valve closure is sufficient to demonstrate compliance, unless the operator has operational information that requires an additional closure percentage for maintaining reliability.

(c) Each operator must take prompt remedial action to correct any valves found inoperable, unless the operator designates an alternative valve.

(d) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

~~(d) For each remote-control valve (RCV) installed in accordance with § 195.258(c) or § 195.418, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 195.446(c) and (e).~~

~~(e) For each alternative equivalent technology installed under § 195.258(c) or (d) or § 195.418(a) that is manually or locally operated (*i.e.,* not an RMV, as that term is defined in § 195.2):~~

~~(1) Operators must achieve a response time of 30 minutes or less, as required by § 195.419(b), through an initial drill and through periodic validation as required by paragraph (e)(2) of this section. An operator must review each phase of the drill response and document the results to validate the total response time, including the identification of a rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.~~

~~(2) Within each pipeline system, and within each operating or maintenance field work unit, operators must randomly select an authorized rupture-mitigation alternative equivalent technology for an annual 30-minute total response time validation drill simulating worst-case conditions for that location to ensure compliance with § 195.419. Operators are not required to close the alternative equivalent technology fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with the drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar~~

~~year, at intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.~~

~~(3) If the 30-minute maximum response time cannot be achieved in the drill, the operator must revise response efforts to achieve compliance with § 195.419 no later than 12 months after the drill. Alternative valve shut-off measures must be in accordance with paragraph (f) of this section within 7 days of the drill.~~

~~(4) Based on the results of the response-time drills, the operator must include lessons learned in:~~

~~(i) Training and qualifications programs;~~

~~(ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and~~

~~(iii) Any other areas identified by the operator as needing improvement.~~

~~(f) Each operator must implement remedial measures as follows to correct any valve installed on an onshore pipeline in accordance with § 195.258(c), or an RMV or alternative equivalent technology installed in accordance with § 195.418, that is indicated to be inoperable or unable to maintain effective shut-off:~~

~~(1) Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain shut-off. An operator may request an extension of the compliance deadline requirements of this section if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that repairing or replacing a valve within 12 months would be economically, technically, or operationally infeasible; and~~

~~(2) Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Alternative compliant valves are not required to comply with valve spacing requirements of this part.~~

~~(g) An operator using an ASV as an RMV, in accordance with §§ 195.2, 195.260, 195.418, and 195.419, must document, in accordance with § 195.419(f), and confirm the ASV shut-in pressures on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required by § 195.419(f), at least each calendar year, but at intervals not to exceed 15 months.~~

~~(h) The requirements of paragraphs (d) through (g) of this section do not apply to gathering lines.~~

8. Additional Modifications to Damage Prevention and Public Awareness[103]

The current damage prevention and public awareness requirements are outdated. PHMSA should modernize these requirements through incorporation of the 3rd edition of API RP 1162, improvements of PHMSA oversight on state damage prevention programs, and inclusion of technological advancements. These steps will improve the safety of America's pipeline network. These proposed changes will also increase participation in state one call centers, close state exemptions to the one call process and improve enforcement of violations. The Damage Prevention Action Center contributed to API's comments on damage prevention concerning participation in state one call system, adoption of leading practices including white lining, positive response, limited ticket size and damage reporting.

The Associations recommend the following changes to the damage prevention and public awareness provisions in Parts 192, 195 and 198.

a. Scope of One Call Tickets

PHMSA should also review the scope of state one call tickets. Tickets often cover large geographic areas. Even if only a small portion of an area will undergo excavation, operators often have to mark large swaths of pipeline, leading to delays in marking and higher locating costs. Reducing the footprint associated with a one-call ticket would reduce the number of locators needed as well as the transportation equipment necessary for marine or marsh locating, amounting to approximately $500,000 per operator annually.

The Associations recommend the following changes:

§ 195.442 Damage prevention program.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum…

(4) If the operator has buried or submerged pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

[103] This section is in response to ANPRM Question # B.7.

(5) Provide for temporary marking of buried or submerged pipelines in the area of excavation activity before, as far as practical, the activity begins.

§ 198.39 Qualifications for operation of one-call notification system.

A one-call notification system qualifies to operate under this subpart if it complies with the following…

(b) It receives and records information from excavators about intended excavation activities (as defined by 49 CFR § 192.614(a) and § 195.442(a)); excavators are required to use white lining to delineate the area of intended excavation.

(c) It promptly transmits to the appropriate operators of underground pipeline facilities the information received from excavators about intended excavation activities.

(d) It maintains a record of each notice of intent to engage in an excavation activity for the minimum time set by the State or, in the absence of such time, for the time specified in the applicable State statute of limitations on tort actions.

(e) It tells persons giving notice of an intent to engage in an excavation activity the names of participating operators of underground ~~pipeline~~ facilities to whom the notice will be transmitted and utilizes an electronic positive response system to promote communication between excavators and facility owners/operators about the status of locates.

(f) It requires membership of all owners and operators of underground facilities except privately owned facilities, located on privately owned property and used only by property owners;

(g) It requires reporting of all excavation damages to all underground facilities and collects information in a format consistent with a nonprofit organization specifically established for the purpose of reducing construction-related damage to underground facilities.

b. Incorporation of API RP 1162 (3RD edition)

PHMSA currently requires operators to comply with the 1st edition of API Recommended Practice 1162 for public awareness purposes. That edition was published twenty-two years ago in 2003 and incorporated in the pipeline safety regulations in 2005. It is significantly outdated. For instance, the 1st edition recommends print materials as an effective means of communication while also encouraging the use of compact discs, radio public service announcements and newspapers. Since 2003, communication methods radically changed with the advent of social media, targeted messaging and geofencing.

Federal pipeline safety regulations should reflect these modernizations, including updating the references to RP 1162 to the most recent 3rd edition, published in 2023. The 3rd edition also introduces the plan-do-check-act cycle within the framework of a public awareness program. This edition also clarifies "shall" statement requirements and establishes a standardized question set for trend analysis and consistent guidance to target audiences, among numerous other improvements compared to the 1st edition. Along with significant safety benefits, modernizing public awareness requirements would result in significant operational savings. Operators cited potential savings of between $225,000 and $380,000 annually per operator in printing and postage costs by allowing digital campaigns. For one operator, the cost of a digital impression represented 1% of a direct mailing, providing an immense opportunity to realize savings while simultaneously improving effectiveness and efficiency. These savings would also be increased through a consistent definition of liaison activities, representing $225,000 annually per operator in additional savings.

c. Definition for "Liaison"

The Associations urge PHMSA to work with pipeline operators and public stakeholders to establish a definition of "liaison" to ensure regulatory consistency. "Liaison" is used in sections 192.615(a)(2) and (c) and 195.402(c)(12) and (e)(1), but there is no codified definition of this term. PHMSA and state auditors interpret this term differently. Providing a clear definition for the requirements for "liaison" activities would improve outreach and engagement with first responders, streamline inspection findings and improve preparedness guidance provided to first responders. As the Agency evaluates an appropriate definition, PHMSA should consider allowing liaison activities outside of a strict face-to-face approach. Such flexibility would save each operator an average of nearly $200,000 annually while improving outreach effectiveness, reach, recall and safety levels.

The Associations recommend adding a definition for "liaison" in Part 192.

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

(c) ***Maintenance and normal operations.*** The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations…

(12) Attempt to ~~E~~establish~~ing~~ and maintain~~ing~~ adequate means of communication with the appropriate public safety answering point (*i.e.,* 9-1-1 emergency call

center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. In lieu of communicating with each individual agency, operators must attempt to establish liaison with the appropriate local emergency coordinating agencies, such as municipal and county emergency managers. Liaison activities are defined as communication and coordination, through a variety of delivery methods, including but not limited to printed and mailed communications, face-to-face, online/virtual, digital, etc., to facilitate mutual understanding and cooperation among people or organizations. Operators must attempt to determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone numbers for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform the officials about the operator's ability to respond to the pipeline emergency and means of communication during emergencies. ~~Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity.~~

The Associations support similar changes in section 195.615(a)(2).

9. Right-of-Way Inspections[104]

a. Inspection Intervals

The Associations encourage PHMSA to include an extension for the timing for right-of-way patrols if the deadline occurs after an extreme weather event. Section 195.412(a) provides that "[e]ach operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way." The Agency should allow for a narrow exception to this timing if an inspection was delayed due to unsafe or unfavorable weather conditions. In those cases, the inspection should be conducted no more than 72 hours after the cessation of the weather event. Also, consistent with a Direct Final Rule issued on July 1, 2025, all right-of-way patrols, including following an extreme weather event, can use remote sensing technologies, such as unmanned aerial systems and satellites, for compliance purposes.[105]

The Associations recommend the following amendments to section 195.412(a):

[104] This section is in response to ANPRM Question # B.7.

[105] Pipeline Safety: Integration of Innovative Remote Sensing Technologies for Right-of-Way Patrols on Gas and Hazardous Liquid Pipelines, 90 Fed. Reg. 28,105 (Jul. 1, 2025).

§ 195.412 Inspection of rights-of-way and crossings under navigable waters.

(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. If an inspection was delayed due to unsafe or unfavorable weather conditions, it should be conducted no more than 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by the personnel and equipment required to perform the inspection. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way, including remote sensing technologies, such as unmanned aerial systems and satellites.

b. Waterway Crossing Inspection Interval

PHMSA should allow operators to develop a risk-based inspection program for pipelines beneath commercially navigable waterways that are substantially below the base elevation of the waterway and where prior inspection and any active monitoring data are available and demonstrate minimal to no risk for damage to the pipeline.

For horizontally directionally drilled installations that are more than 30 feet below the base elevation of the waterway, the Associations are proposing to extend the inspection interval to 10 years, with the ability to extend this maximum inspection interval through risk-based analysis. It is important to note that these crossings are subject to preventive and mitigative measures and inspection on a 5-year maximum interval using ILI technologies to assess the condition of the pipeline crossings with regard to anomalies that may be present, coating conditions, corrosion control, and other integrity related requirements in part 195. In addition, each pipeline that crosses a navigable waterway is subject to the annual information analysis required under §195.452(g), which would include evaluation of available information, including active monitoring systems that may indicate any conditions that have affected the depth of cover at a pipeline crossing (dredging operations, USGS field gauge monitoring of waterways, satellite imagery, etc.), where a change in conditions may warrant more frequent inspections. Additionally, under §195.414, inspections must be conducted following an extreme weather event or natural disaster that has the likelihood of damage to infrastructure by scouring, bank avulsion, or movement of the soil surrounding the pipeline, including flood events that exceed the river, shoreline, or creek high-water banks in the area of the pipeline. If these inspections indicate a need for immediate or more frequent inspections of the pipeline crossing, operators are required to respond as appropriate.

The Associations recommend the following amendments to section 195.412(b):

§ 195.412 Inspection of rights-of-way and crossings under navigable waters.

(b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years and on any day within the calendar month due, inspect each crossing under a navigable waterway to determine the condition of the crossing. Operators of pipelines at depths greater than 30 feet below the base elevation of the waterway crossing along the entire extent of the crossing with no evidence of threats from erosion, scour or third-party interference from prior inspections and active monitoring systems that may be in place may apply for a variance in navigable waterway crossing intervals. Operators must document their basis for the variance

(c) Additional inspections must also be conducted as required by §195.414(a)-(c).

10. Drug and Alcohol Testing Requirements[106]

The Associations have identified several requirements in DOT's and PHMSA's drug and alcohol program regulations[107] that impose undue burdens on stakeholders. As discussed further below, modifications to these provisions would improve efficiency in the drug and alcohol testing process, provide additional clarity to regulated employers, and enhance the ability to achieve the objectives of the regulations. Some of these recommendations are administrative and may not require a change in regulation to achieve the objectives.

a. Annual Random Testing Rates

PHMSA should reevaluate its model for annual fluctuation of the random testing rates. Currently, PHMSA's regulations establish 50 percent as the minimum annual random drug testing rate for employees of operators and contractors.[108] This random drug testing rate is based on the reported positive rate in the industry's random drug tests, which is submitted in operators' annual drug and alcohol management information system (DAMIS) reports.[109] PHMSA's Administrator may lower the random drug testing rate to 25 percent if the reported positive drug test rate is below 1.0 percent for two consecutive calendar years. On the other hand, if the random drug testing rate is 25 percent and the reported positive drug test rate is equal or greater than 1.0 percent, the Administrator is required to return the random drug testing rate to 50 percent. In November 2024, PHMSA notified operators that it was increasing

[106] This section is in response to ANPRM Question # B.11.
[107] 49 C.F.R. Parts 40 and 199.
[108] 49 C.F.R. § 199.105(c)(1).
[109] 49 C.F.R. § 199.119(a).

the minimum annual drug testing rate from 25 percent to 50 percent for calendar year 2025 due to the reported positive drug test rate reported in calendar year 2023.[110]

The repeated fluctuation of testing rates presents undue challenge to operators. Operators are unable to promptly adjust operationally to these potential fluctuations, especially at the risk of not being able to comply. It would be more appropriate to set the minimum rate at 25 percent, rather than having an annual sliding scale up to 50 percent.

§ 199.105 Drug tests required.

(c) *Random testing.*

(1) ~~Except as provided in paragraphs (c)(2) through (4) of this section,~~ The minimum annual percentage rate for random drug testing shall be ~~50~~ 25 percent of covered employees.

~~(2) The Administrator's decision to increase or decrease the minimum annual percentage rate for random drug testing is based on the reported positive rate for the entire industry. All information used for this determination is drawn from the drug MIS reports required by this subpart. In order to ensure reliability of the data, the Administrator considers the quality and completeness of the reported data, may obtain additional information or reports from operators, and may make appropriate modifications in calculating the industry positive rate. Each year, the Administrator will publish in the Federal Register the minimum annual percentage rate for random drug testing of covered employees. The new minimum annual percentage rate for random drug testing will be applicable starting January 1 of the calendar year following publication.~~

~~(3) When the minimum annual percentage rate for random drug testing is 50 percent, the Administrator may lower this rate to 25 percent of all covered employees if the Administrator determines that the data received under the reporting requirements of § 199.119 for two consecutive calendar years indicate that the reported positive rate is less than 1.0 percent.~~

~~(4) When the minimum annual percentage rate for random drug testing is 25 percent, and the data received under the reporting requirements of § 199.119 for any calendar year indicate that the reported positive rate is equal to or greater than 1.0 percent, the Administrator will increase the minimum annual percentage rate for random drug testing to 50 percent of all covered employees.~~

110 89 Fed. Reg. 91,887.

(2) The selection of employees for random drug testing shall be made by a scientifically valid method, such as a random number table or a computer-based random number generator that is matched with employees' Social Security numbers, payroll identification numbers, or other comparable identifying numbers. Under the selection process used, each covered employee shall have an equal chance of being tested each time selections are made.

(3) The operator shall randomly select a sufficient number of covered employees for testing during each calendar year to equal an annual rate not less than the minimum annual percentage rate for random drug testing determined by the Administrator. If the operator conducts random drug testing through a consortium, the number of employees to be tested may be calculated for each individual operator or may be based on the total number of covered employees covered by the consortium who are subject to random drug testing at the same minimum annual percentage rate under this subpart or any DOT drug testing rule.

(4) Each operator shall ensure that random drug tests conducted under this subpart are unannounced and that the dates for administering random tests are spread reasonably throughout the calendar year.

(5) If a given covered employee is subject to random drug testing under the drug testing rules of more than one DOT agency for the same operator, the employee shall be subject to random drug testing at the percentage rate established for the calendar year by the DOT agency regulating more than 50 percent of the employee's function.

(6) If an operator is required to conduct random drug testing under the drug testing rules of more than one DOT agency, the operator may—

(i) Establish separate pools for random selection, with each pool containing the covered employees who are subject to testing at the same required rate; or

(ii) Randomly select such employees for testing at the highest percentage rate established for the calendar year by any DOT agency to which the operator is subject.

b. Alternate Random Selections

The Associations urge PHMSA to allow alternate random selections if a selected employee is unavailable for testing. Specifically, the Associations request that PHMSA allow for inclusion of an alternate selection process to be permitted in the employer's submitted random selection plans. Currently, PHMSA drug testing regulations do not allow operators to designate an alternate, if a selected employee is unavailable, in the random selection process.[111] Such an allowance would help operators to keep testing on schedule if selected employees were unavailable; ensure compliance with required testing rates; reduce operational delays and administrative burdens; maintain fairness in the selection process; and avoid potential violations due to missed tests.

The Associations recommend adding the following provision to § 199.105:

> **§ 199.105(d) Drug tests required.**
>
> (g) ***Alternate selection.*** An operator may include a documented process for alternate random selections in its random testing plan, to be used only when the initially selected employee is unavailable during the testing window. The process must ensure randomization is preserved and must be approved by the operator's Designated Employer Representative.

c. Stand-Down Without Waiver

The Associations request that PHMSA modify 49 C.F.R. § 199.7 to allow operators to stand down employees who test positive for a substance with no history of medical use prior to a medical review officer (MRO) completing the verification process.[112] Currently, operators are prohibited from standing down employees unless a waiver has been granted by PHMSA.[113]

Operators should be given flexibility to stand down employees, in particular employees who have tested positive for substances with no history of medical use, from safety-sensitive functions during the time between the laboratory notifying the MRO of a positive test result and the MRO verifying the test result. The inability to stand down employees who test positive for substances with no known medical history of use during this waiting period not only disadvantages the safe operation and maintenance of pipeline systems, but places unnecessary administrative burdens associated with requesting a waiver from PHMSA on employers.

The Associations recommend adding the following provision to § 199.7:

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[111] The Federal Motor Carrier Safety Administration (FMCSA) allows for the selection of an alternate driver for random testing only "if the primary driver selected will not be available for testing for the entire selection period because of long-term absence due to layoff, illness, injury, vacation or other circumstances." FMSCA's Random Testing Questions and Answers, Q11 (last updated July 12, 2022), *available at* https://www.fmcsa.dot.gov/regulations/drug-alcohol-testing/random-testing. *See also* 49 C.F.R. § 382.305.
[112] The DOT Procedures outline in detail the verification process for MROs, which is to receive test results from the laboratory, verify a positive or negative result, and only then contact the operator to report the test result. *See* 49 C.F.R. Part 40, Subpart G – Medical Review Officers and the Verification Process.
[113] 49 C.F.R. § 199.7.

§ 199.7 Stand-down waiver

(d) Operators may stand down employees who test positive for Schedule I substances with no valid medical use without a waiver.

d. Operator Oversight of Contractor Compliance

The Associations urge PHMSA to shift the responsibility of contractor compliance with Part 199 from operators to the contractors themselves. Currently, operators are responsible for ensuring contractor compliance with drug testing, education, and training as required by § 199.115. PHMSA's alcohol misuse requirements contain a similar requirement in § 199.245. PHMSA should also remove the requirement for operators to include contract companies in their DAMIS reports and require contractors to submit their own drug and alcohol testing results.

PHMSA's mandate for operators to maintain oversight of contractors' drug and alcohol programs to ensure compliance has presented several challenges:

- **Multiple Contractors**: Operators may have numerous contractors performing or ready to perform covered functions, potentially involving over 300 contractor companies and more than 100,000 employees. Operators do not have the personnel to manage the drug and alcohol testing for these contractors.
- **Lack of Access to Test Data**: Operators do not have direct access to contractor test data.
- **Reliance on Third-Party Auditors**: Operators frequently engage third-party auditing companies to assist with compliance. These auditors often review the same contractor companies repeatedly, as they collaborate with multiple operators.
- **Cost Implications**: The use of third-party auditing companies can cost operators a minimum of $30,000 or more annually, depending on the number of contractor companies involved. Additionally, operator field personnel must perform verification checks to ensure on-site contractor personnel comply with the third-party system, leading to further costs and reduced productivity. Contractors also incur costs for enrolling in third-party auditing programs.
- **Redundant Anti-Drug Plans**: Third-party auditing companies often sell anti-drug plans to contractor companies, which may duplicate existing codes.
- **Reporting Requirements**: Operators are required to include contractor annual drug and alcohol testing statistics in their DAMIS reports.

The current requirement for operators to ensure contractor compliance with §§ 199.115 and 199.245 imposes significant administrative and operational burdens. The Associations outline the following benefits for removing this requirement, including focusing on efficiency, accountability, and resource optimization:

- **Enhanced Contractor Accountability:** By placing the onus directly on contractors to comply with Part 199, the shift will encourage contractors to take full responsibility for their compliance, leading to improved adherence to regulations and standards.
- **Streamlined Operations:** Operators currently spend a considerable amount of time and resources monitoring contractor compliance. By refocusing this obligation onto contractors directly, operators can reallocate these resources to core operational activities, enhancing overall efficiency and productivity.
- **Reduced Administrative Burden:** The administrative tasks associated with ensuring contractor compliance are extensive. Eliminating this requirement will reduce paperwork, audits, and oversight activities, allowing operators to focus on their primary responsibilities.
- **Improved Contractor Selection:** With contractors being solely responsible for their compliance, operators can prioritize selecting contractors with proven track records of regulatory adherence. This will foster a competitive environment where only the most compliant and reliable contractors are chosen.
- **Regulatory Clarity:** Simplifying the compliance landscape by removing this requirement will provide clearer guidelines for both operators and contractors. This clarity will help in avoiding misunderstandings and ensuring that all parties are aware of their responsibilities.

While the Associations' members agree with ensuring that a contractor when hired has a compliance testing program, the ongoing compliance obligation is not cost-effective. By removing or amending the requirements in §§ 199.115 and 199.245 for operators to ensure contractor compliance with Part 199, this regulatory change will lead to enhanced accountability, streamlined operations, reduced administrative burdens, improved contractor selection, and greater regulatory clarity. Furthermore, it will ultimately benefit both operators and contractors, fostering a more efficient and effective operational environment.

The Associations recommend the following modifications to §§ 199.115 and 199.245:

> **§ 199.115 Contractor employees.**
>
> With respect to those employees who are contractors or employed by a contractor, an operator may provide by contract that the drug testing, education, and training required by this subpart be carried out by the contractor provided:

(a) ~~The operator remains responsible for ensuring that the requirements of this part are complied with; and~~ Contractors are independently responsible for their compliance with this part. Operators are not obligated to oversee contractor anti-drug programs established by this subpart.
(b) The contractor allows access to property and records by the operator, the Administrator, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purpose of monitoring the operator's compliance with the requirements of this part.

§ 199.245 Contractor employees.

(a) With respect to those covered employees who are contractors or employed by a contractor, an operator may provide by contract that the alcohol testing, training and education required by this subpart be carried out by the contractor. ~~provided:~~
(b) ~~The operator remains responsible for ensuring that the requirements of this subpart and part 40 of this title are complied with; and~~ Contractors are independently responsible for their compliance with this part. Operators are not obligated to oversee contractor alcohol misuse programs established by this subpart.
(c) The contractor allows access to property and records by the operator, the Administrator, any DOT agency with regulatory authority over the operator or covered employee, and, if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purposes of monitoring the operator's compliance with the requirements of this subpart and part 40 of this title.

e. Anti-Drug Plan

The Associations urge PHMSA to eliminate the requirement in § 199.101 for operators to maintain and follow a written anti-drug plan. Requirements for drug testing are already comprehensively covered in DOT's regulations found at 49 C.F.R. Part 40, as well as throughout Part 199. These regulations provide detailed guidelines and procedures that operators must follow, making a separate written plan redundant. The existing regulations are robust and sufficient to ensure compliance and safety without the need for additional documentation.

Eliminating the written plan requirement would streamline compliance efforts, allowing operators to focus on the practical implementation of drug and alcohol testing programs as outlined in the existing regulations. This would enhance operational efficiency and ensure that resources are directed towards effective program execution rather than redundant documentation. It would also simplify the regulatory framework, supporting a more straightforward and manageable compliance process, benefiting operators, PHMSA, and state agencies. A simplified regulatory environment fosters better compliance and reduces the risk of inadvertent non-compliance due to complex and overlapping requirements.

PHMSA stands alone among the five regulated drug and alcohol testing DOT modes and the USCG in requiring a written anti-drug plan. FMCSA,[114] Federal Railroad Administration (FRA),[115] Federal Transit Administration (FTA),[116] Federal Aviation Administration (FAA),[117] and USCG[118] all regulate drug and alcohol testing without mandating a written plan. This inconsistency among DOT operating modes places an unnecessary administrative burden on operators under PHMSA's authority, which could be alleviated by aligning PHMSA's requirements with those of other modes.

The elimination of the written anti-drug plan requirement would not compromise the integrity or effectiveness of drug and alcohol testing programs. Instead, it would align PHMSA's requirements with those of other regulated modes, eliminate redundancy, and enhance overall efficiency. This change is not only logical but necessary to ensure a fair and streamlined regulatory environment. The Associations recommend PHMSA remove and reserve § 199.101.

f. Previous Employer History

The Associations propose that DOT and PHMSA permit the use of electronic signatures on the DOT 40.25 Previous Employer History document.[119,] This would align with current DOT policies, improving efficiency and reducing administrative burdens.

Pursuant to 49 C.F.R. § 40.25, employers must obtain an employee's written consent, including a wet signature, to request certain information about the employee from his or her previous employer.[120] This requirement for a wet signature, however, is increasingly cumbersome and

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114 FMCSA requires drug and alcohol testing for drivers of commercial motor vehicles but does not mandate a written anti-drug plan. *See* 49 C.F.R. Part 382.

115 FRA requires drug and alcohol testing for railroad employees, which includes comprehensive testing requirements but no written plan mandate. *See* 49 C.F.R. Part 219.

116 FTA required drug and alcohol testing for employers that receive financial assistance from FTA and contractors of those employers, but does not require a written plan. *See* 49 C.F.R. Part 655

117 FAA regulates drug and alcohol testing for aviation employees, but does not require a written anti-drug plan. *See* 14 C.F.R. Part 120.

118 USCG mandates drug testing for maritime employees, focusing on testing protocols without a written plan requirement. *See* 46 C.F.R. Part 16.

119 Part 199 defines DOT Procedures as "the Procedures for Transportation Workplace Drug and Alcohol Testing Programs" found in 49 C.F.R. Part 40. Furthermore, § 199.5 requires the Part 199 the drug and alcohol programs to conducted in accordance with Part 199 and DOT Procedures. DOT Procedures require an employer to request information about a DOT-regulated employee from the employee's previous employer if the employee is intending to perform safety-sensitive duties. 49 C.F.R § 40.25.

120 *In the Matter of Wyoming Refining Company*, CPF 5-2021-031-NOPV (Aug. 11, 2021) (To comply with § 40.25, "the employer must first get a "wet ink" signature from each employee for each prior DOT employer who

outdated in the context of modern business practices. Wet signatures require physical handling of documents, which is time-consuming, administratively inefficient, and leads to delays. Even after a wet signature has been obtained, documents are frequently faxed or emailed, highlighting the redundancy in the requirement when the document will ultimately be transmitted electronically. In contrast, electronic signatures can be applied instantly, streamlining the workflow and reducing the time required to complete the document. Electronic signatures also ensure that documents are both secure and easily accessible in their final electronic form.

DOT already permits electronic signatures on the Custody and Control Form for DOT drug testing. This precedent demonstrates the DOT's recognition of the validity and security of electronic signatures. Extending this policy to the 40.25 Previous Employer History document would be a logical and consistent step, further modernizing DOT's documentation processes.

The Associations urge DOT and PHMSA to consider this change and make the recommend regulatory change to § 40.25 to better serve the needs of the industry and improve overall operational effectiveness.

> **§ 40.25 Must an employer check on the drug and alcohol testing record of employees it is intending to use to perform safety-sensitive duties?**
>
> (a)
> (1) Yes, as an employer, you must, after obtaining an employee's written or electronic consent, request the information about the employee listed in paragraphs (b) through (j) of this section. This requirement applies only to employees seeking to begin performing safety-sensitive duties for you for the first time (*i.e.,* a new hire, an employee transferring into a safety-sensitive position). If the employee refuses to provide this written consent, you must not permit the employee to perform safety-sensitive functions.

g. Alcohol Testing Form

The Associations request that DOT and PHMSA modify the requirement for DOT Alcohol Testing Form (ATF) to allow the use of electronic alcohol test forms with electronic signatures. The current practice for non-DOT drug and alcohol testing includes the use of electronic breath alcohol testing forms with electronic signatures, however, DOT Procedures require use a three-part carbonless manifold form for the DOT ATF.[121]

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employed the employee during any period during the two years before the date of the employee's application with the employer.")

[121] 49 C.F.R. § 40.225.

Certain benefits would accompany the use of electronic ATFs, including enhancing compliance, improving efficiency, and leveraging technological advancements. Specifically, the use of electronic forms simplifies the testing process, reducing the time required for data entry and the risk of human error associated with manual entries. It allows for immediate submission and verification of test results, which facilitates quicker detection and response to non-compliance issues. It also provides a secure, traceable record of actions taken during the testing process, which is crucial for audits and regulatory reviews. Additionally, transitioning to electronic forms can lead to significant cost savings by reducing the need for physical storage, paper, and administrative overhead. Electronic forms can be integrated with existing human resources and compliance management systems, ensuring seamless accessibility, data flow, and reduction of duplicative efforts. Furthermore, modern signature technologies offer robust security features, including encryption and multi-factor authentication, ensuring the authenticity and confidentiality of test results. For these reasons, the Associations urge DOT and PHMSA to transition to an electronic format for DOT ATFs.

h. Duplicative Regulations

PHMSA should review and amend Part 199 to reference DOT Procedures Part 40 requirements regarding MROs, service agents, and testing procedures. Part 40 contains prescriptive requirements for MROs, service agents, and testing procedures, which PHMSA's regulations need not duplicate in regulatory text. By eliminating any potential duplicative regulations, PHMSA avoids potential overlap and resulting confusion, and ensuring consistency and reliability in the drug and alcohol testing process across different DOT operating modes.

i. Oral Testing Laboratories

In May 2023, DOT issued a final rule amending its drug testing program in Part 40 to include oral fluid testing.[122] While DOT issued Oral Fluid Specimen Collection Procedures Guidelines in January 2025,[123] the Department has been unable to fully implement oral fluid testing as the Department of Health and Human Services has not yet certified at least two laboratories.[124] This delay in certifying labs has, unfortunately, impacted DOT's ability to implement a reliable drug testing method that provides results that are defensible in audits and court and reduces false positives and negatives. The Associations urge DOT and PHMSA to support any efforts to designate oral fluid testing labs.

[122] 88 Fed. Reg. 27,596.
[123] DOT Oral Fluid Specimen Collection Procedures Guidelines (Jan. 2025).
[124] Part 40 Final Rule - DOT Summary of Changes | US Department of Transportation.

j. Duplicative Inspections

The Associations share concerns from operators regarding the continuation of duplicative drug and alcohol program inspections performed by PHMSA and state agencies. Section 117 of the PIPES Act of 2020 requires PHMSA to amend the auditing program for drug and alcohol regulations to minimize duplicative audits of the same operators by PHMSA and State agencies.[125] However, operators continue to face duplicative drug and alcohol inspections on an annual basis. The Associations request PHMSA issue guidance regarding the implementation of Section 117 of the PIPES Act and consider amending Part 199 to allow for the reciprocity of drug and alcohol inspections between PHMSA and State agencies and State agency to State agency.

k. Test Conversion

The Associations request that PHMSA amend Part 199 to allow for the conversion of a DOT test result to a non-DOT test result without requiring agency approval. To convert a DOT test result to a non-DOT test result, an employer must direct its request for conversion to the appropriate DOT Agency Drug and Alcohol Program Manager.[126] This process is burdensome to employers and program managers as specific employee data is not shared with the PHMSA DOT Agency Program Manager to approve or validate a conversion request.

11. Additional Modifications to Reporting Requirements[127]

The Associations provide responsive comments below on Part 195 reporting requirements. The American Petroleum Institute and the Center for LNG will provide additional comments specific to Part 193 in separate comments in this docket.

a. Accident Reporting Threshold

The Associations urge DOT to modify the property damage threshold for reporting hazardous liquid pipeline accidents[128] to be consistent with the reporting requirements for natural gas operators.[129] PHMSA's current regulations require an accident report where a release of hazardous liquid or carbon dioxide results in several listed consequences including estimated property damage exceeding $50,000.[130] However, the threshold that applies to natural gas

[125] Pub. Law 116-206, div. R, title I, §117 (Dec. 27, 2020).
[126] 49 C.F.R. §§ 40.13(g), 40.41(a), and 40.227(a).
[127] This section is in response to ANPRM Question # B.4.
[128] Section 195.50(e)("[e]stimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000").
[129] 49 C.F.R. § 191.3 (Definition of an Incident).
[130] *Id.*

operators is $149,700, almost three times larger.[131] The Associations raised this concern in response to the U.S. Department of Transportation's Request for Information[132] and appreciate PHMSA's willingness to address this issue in the Direct Final Rule issued on July 1, 2025.[133]

While PHMSA included amendments to section 195.50(e) in the Direct Final Rule, the Agency did not amend section 195.52(a)(3). The Associations support parallel changes to section 195.52(a)(3) for consistency purposes.

The Associations recommend the following amendments:

> **§ 195.52 Immediate notice of certain accidents.**
>
> (a) ***Notice requirements.*** At the earliest practicable moment following discovery, of a release of hazardous liquid or carbon dioxide transported resulting in an event described in § 195.50, but no later than one hour after confirmed discovery, the operator of the system must give notice, in accordance with paragraph (b) of this section of any failure that:
>
> (1) Caused a death or a personal injury requiring hospitalization;
>
> (2) Resulted in either a fire or explosion not intentionally set by the operator;
>
> (3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding ~~$50,000~~ $149,700. For adjustments for inflation observed in calendar year 2026 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix D to part 195.
>
> (4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or
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> (5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

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[131] *See* 49 C.F.R. § 191.3; *see also,* https://www.phmsa.dot.gov/incident-reporting (last accessed on July 16, 2025).

[132] LEPA and API Comments on DOT RFI, https://www.regulations.gov/comment/DOT-OST-2025-0026-0874 (filed on May 5, 2025).

[133] *Pipeline Safety: Property Damage Definition for Incident Reporting on Gas Pipelines and Accidents on Hazardous Liquid Pipelines,* 90 Fed. Reg. 28,050 (July 1, 2025). In this Direct Final Rule, PHMSA announced its intention to update section 195.50(e)

b. Use of technology for immediate reports

The Associations also encourage PHMSA to work with the USCG and the EPA to update the electronic reporting system beyond telephonic systems. This is a burden on operators and an example of government inefficiencies.

c. Deadline for Annual Reports

The current deadline for an Annual Report for Hazardous Liquid and Carbon Dioxide Pipeline Systems (DOT Form PHMSA F 7000-1.1) is June 15th. While the Associations recognize that PHMSA is in the process of moving the annual reporting deadline for natural gas pipelines from March to June, the Associations recommend that the Agency take the opportunity to create a uniform deadline of August for all annual reports regardless of commodity transported. Hazardous liquid pipeline operators have been working with the June 15th deadline since 2005.[134] Annual reports have become more complex as PHMSA continues to amend the reports and collect additional information. An August deadline for all operators will ease reporting burdens, reduce the opportunity for errors by allowing the time for data to be appropriately verified, and provide consistent deadlines for both natural gas and hazardous liquid operators. Since PHMSA generally does not aggregate the data until the following year, this requested change should not impact the timeliness of data delivery to all stakeholders.

The Associations recommend the following changes:

> **195.49 Annual report.**
>
> Each operator must annually complete and submit DOT Form PHMSA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. An operator must submit the annual report by ~~June~~ August 15 each year~~, except that for the 2010 reporting year the report must be submitted by August 15, 2011~~. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, carbon dioxide pipelines, and fuel grade ethanol pipelines. For each state a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each state.

d. Safety-Related Conditions

Similar to INGAA's comments in response to DOT's Request for Information,[135] the Associations seek revisions to safety-related condition reporting. Section 195.55(a)(6) requires

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[134] *See* Pipeline Safety: Hazardous Liquid Pipeline Operator Annual Reports, 69 Fed. Reg. 537, 539 (Jan. 6, 2004). *See also,* 49 C.F.R. § 195.49.

[135] INGAA Comments in Response to DOT RFI, https://www.regulations.gov/comment/DOT-OST-2025-0026-0872 (May 5, 2025).

reporting of "[a]ny safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline."[136] PHMSA inspectors have taken the position that a 20% reduction in pressure, no matter the reason, is reportable as a safety-related condition. This was not the intent of the statute or the initial code drafters. Operators were supposed to report only "glaring, hazardous conditions." [137]

Taking a pressure restriction either voluntary or required by other sections of the pipeline safety regulations does not automatically make the condition a hazard to life, property, or the environment and does not always constitute a significant restriction in the pipeline facility. Under the plain reading of the statutory requirements, conditions that are immediately made safe upon discovery, whether through a pressure reduction or other means, should not be reported as they are no longer a hazard. As a result, pressure reductions typically taken as a response to an anomaly identified during the integrity management process should not be reportable as a safety-related condition. The integrity management process is already in place to manage pipeline safety. This additional requirement becomes redundant and adds little value but increases paperwork for both PHMSA and operators.

The Associations propose the following amendments to sections 195.55(b) and 191.23(b):

> **§ 195.55 Reporting safety-related conditions.**
>
> (b) A report is not required for any safety-related condition that—
>
> (1) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water;
>
> (2) Is an accident that is required to be reported under § 195.50 or results in such an accident before the deadline for filing the safety-related condition report; or
>
> (3) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are

[136] 49 C.F.R. § 195.55(a)(6).
[137] Reporting Unsafe Conditions on Gas and Hazardous Liquid Pipelines and Liquefied Natural Gas Facilities, 53 Fed. Reg. 24,942, 24,943 (July 1, 1988)(The Agency acknowledged that "…operators were expected to disclose only glaring, hazardous conditions, which might, if left to linger, constitute an imminent danger or potentially cause an incident").

required for all conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline; or.

(4) Is a pressure reduction in response to anomaly condition(s) identified and managed through the Integrity Management Program as required by 195.452.

§ 191.23 Reporting safety-related conditions.

(b) A report is not required for any safety-related condition that—

(1) Exists on a master meter system, a reporting-regulated gathering pipeline, a Type C gas gathering pipeline with an outside diameter of 12.75 inches or less, a Type C gas gathering pipeline covered by the exception in § 192.9(f)(1) of this subchapter and therefore not required to comply with § 192.9(e)(2)(ii), or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline (other than an UNGSF or an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for:

(i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and

(ii) Any condition under paragraph (a)(10) of this section.

(5) Exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction; or.

(6) Is a pressure reduction in response to anomaly condition(s) identified and managed through the Integrity Management Program as required by 49 CFR 192 Subpart O.

12. Incorporated Standards[138]

The Associations provide the following specific recommended practices and specifications for PHMSA's review and incorporation into Part 195.

[138] This section is in response to ANPRM Question # B.4.

a. API Recommended Practice 1181

The Associations encourage PHMSA to incorporate API RP 1181 (Pipeline Operational Status Determination) by reference in Part 195. This recommended practice provides guidance for operations, inspections, and maintenance activities based on the operational status of the pipeline, *i.e.,* pre-commissioned, active, idled or abandoned. Incorporating it into the pipeline safety regulations would reduce the burden operators currently face to maintain pipe that has does not contain any hydrocarbons and is in an idle state. This proposed revision would also reduce the burden for both operators and PHMSA in performing inspections of operator integrity management programs by minimizing the level of inspection effort placed on idled assets that represent minimal to no risk to public safety and the environment and focus resources on inspection of active pipelines and facilities. This proposed revision would also reduce the burden for both operators and PHMSA in performing inspections of operator integrity management programs by minimizing the level of inspection effort placed on idled pipeline assets that represent minimal to no risk to public safety and the environment and instead focus resources on the inspection of active pipelines and facilities.

> **195.3 What documents are incorporated by reference partly or wholly in this part?**
>
> (b) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571; phone: (202) 682-8000; website: *www.api.org/*.
>
> (24) API Recommended Practice 1181, "Pipeline Operational Status Determination," 1st edition, 2019, (API RP 1181), IBR approved for §§ 195.402(c)(10) and (c)(16), 195.416(a), 195.444(a), and 195.452.

b. API Recommended Practice 1162

PHMSA should modernize its public awareness requirements by incorporating the 3rd edition of API RP 1162 (Public Awareness Programs for Pipeline Operators) published in 2023 compared with the currently referenced version, published in 2003.

> **195.3 What documents are incorporated by reference partly or wholly in this part?**
>
> (b) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571; phone: (202) 682-8000; website: *www.api.org/*.

(7) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," ~~1st~~ 3rd edition, ~~December 2003~~ February 2023, (API RP 1162), IBR approved for § 195.440(a), (b), and (c).

c. API Recommended Practice 1130

The Associations recommend that PHMSA incorporate the 2nd edition of API RP 1130, *Computational Pipeline Monitoring for Liquids* (2022) in Part 195. The 2nd edition of the recommended practice was published in 2022 and reflects advances in technology. In comparison, PHMSA continues to rely on the 1st edition which was published 18 years ago in 2007.

The Associations recommend the following changes:

195.3 What documents are incorporated by reference partly or wholly in this part?

(b) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571; phone: (202) 682-8000; website: *www.api.org/*.

(6) API Recommended Practice 1130, "Computational Pipeline Monitoring for Liquids: Pipeline Segment," ~~3rd edition, September 2007~~,[139] 2nd edition, April 2022 (API RP 1130), IBR approved for §§ 195.134 and 195.444.

d. ASTM F2619

The Associations recommend that PHMSA incorporate ASTM F2619 (Standard Specification for High-Density Polyethylene (PE) Line Pipe), 2019 edition, into Part 192. This specification covers the requirements and test methods for high-density polyethylene materials, line pipes, and fittings. Many gathering pipelines are constructed to this specification.

13. Gathering Lines[140]

The Associations support the Agency's decision to withdraw its Advisory Bulletin on Section 114 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (ADB–2021–01).[141] In that notice, the Agency stated it is also rescinding "any PHMSA policy

[139] While section 195.3 references "the 3rd edition" of API RP 1130, that is an error. The September 2007 edition was the first edition of the recommended practice. Prior to 2007, API had published API 1130 (1ST edition, 1995) and then API 1130 (2ND edition, 2002). API then moved to a recommended practice publishing the 1st edition of the recommended practice in 2007 and the second edition in 2022.

[140] This section is in response to ANPRM Question # B.3.

[141] Pipeline Safety: Recission of Advisory Bulletin on Section 114 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020, 90 Fed. Reg. 2,6085 (June 18, 2025).

statements, letters of interpretation, guidance documents, congressional testimony, and public statements that rely on or assert the reading of the section 114 mandate expressed in ADB–2021–01.[142] Consistent with that announcement, the Associations request that PHMSA withdraw the interpretation issued to Paradox Pipeline[143] and revise its inspection question sets to remove section 114 questions.[144]

The Associations also agree with PHMSA's recent Notice of Proposed Rulemaking on Incidental Gathering Lines.[145] The Agency proposes to amend section 192.8(a)(5) to remove the limitation of "new, replaced, relocated, or otherwise changed" and allow gathering line operators to use the incidental gathering designation without a mileage restriction. If that rule is finalized, as proposed, the incidental gathering designation would not be available for new gathering pipelines. This is a commonsense change.

14. Definitions[146]

The Associations have reviewed various terms used in the pipeline safety regulations and propose the following changes to provide clarity and remove inefficiencies:

a. Liaison with local emergency coordinating agencies

The Associations seek a codified definition of "liaison" in 195.402(c)(12).

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

(c) ***Maintenance and normal operations.*** The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations…

(12) Attempt to ~~E~~establish~~ing~~ and maintain~~ing~~ adequate means of communication with the appropriate public safety answering point (*i.e.,* 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. In lieu of communicating with each individual agency, operators must attempt to establish liaison with the appropriate local emergency coordinating agencies, such as

[142] *Id.* at 26,090.
[143] PHMSA Letter of Interpretation, PI-23-0011, https://www.phmsa.dot.gov/regulations/title49/interp/pi-23-0011 (Apr. 26, 2024).
[144] *See* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2025-01/PHMSA-Gas-Transmission-GT-2025-01-IA-Question-Set-January-2025.pdf at 258; *See also,* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2025-01/PHMSA-Hazardous-Liquid-HL-2025-01-IA-Question-Set-January-2025.pdf at 193.
[145] Pipeline Safety: Codify Enforcement Discretion on Incidental Gathering Lines, 90 Fed. Reg. 28,597 (July 1, 2025).
[146] This section is in response to ANPRM Question # B.2.

municipal and county emergency managers. Liaison activities are defined as communication and coordination, through a variety of delivery methods, including but not limited to printed and mailed communications, face-to-face, online/virtual, digital, etc., to facilitate mutual understanding and cooperation among people or organizations. Operators must attempt to determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone numbers for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform the officials about the operator's ability to respond to the pipeline emergency and means of communication during emergencies.

b. New and Novel Technologies

For clarification purposes, PHMSA should revise its definition of "new and novel technologies" in section 190.3. Technologies related to pipeline construction, operations, and safety continue to advance ahead of regulatory changes. Operating companies, technology service providers, and academia are vested in and are driving improvements in inspection technologies, analytics, and engineering methods for assessing the safety of energy pipeline systems. This section should not be limited to "new construction."

§ 190.3 Definitions.

New and novel technologies means any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in 49 CFR parts 192, 193, or 195, due to technology or design advances and innovation for new construction, pipeline operations and maintenance, and inspection and integrity management. Technologies that are addressed in consensus standards that are incorporated by reference into parts 192, 193, and 195 are not "new or novel technologies."

IV. Conclusion

The Associations appreciate PHMSA's consideration of these comments and look forward to continued discussion on these topics.

Respectfully submitted,

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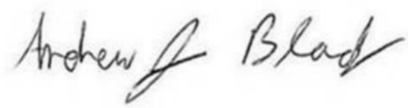

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