DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 195

[Docket No. PHMSA–2010–0229; Amdt. No. 195–102]

RIN 2137–AE66

Pipeline Safety: Safety of Hazardous Liquid Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: In response to congressional mandates, NTSB and GAO recommendations, lessons learned, and public input, PHMSA is amending the Pipeline Safety Regulations to improve the safety of pipelines transporting hazardous liquids. Specifically, PHMSA is extending reporting requirements to certain hazardous liquid gravity and rural gathering lines; requiring the inspection of pipelines in areas affected by extreme weather and natural disasters; requiring integrity assessments at least once every 10 years of onshore hazardous liquid pipeline segments located outside of high consequence areas and that are ''piggable'' (*i.e.,* can accommodate in-line inspection devices); extending the required use of leak detection systems beyond high consequence areas to all regulated, non-gathering hazardous liquid pipelines; and requiring that all pipelines in or affecting high consequence areas be capable of accommodating in-line inspection tools within 20 years, unless the basic construction of a pipeline cannot be modified to permit that accommodation. Additionally, PHMSA is clarifying other regulations and is incorporating Sections 14 and 25 of the PIPES Act of 2016 to improve regulatory certainty and compliance.

DATES: The effective date of this final rule is July 1, 2020. The incorporation by reference of certain publications listed in the rule was approved by the Director of the Federal Register as of March 24, 2017 and March 6, 2015.

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SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

In recent years, there have been significant hazardous liquid pipeline accidents, most notably the 2010 crude oil spill near Marshall, MI, during which at least 843,000 gallons of crude oil were released, significantly affecting the Kalamazoo River. In response to accident investigation findings, incident report data and trends, and stakeholder input, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is amending the hazardous liquid pipeline safety regulations to improve protection of the public, property, and the environment by closing regulatory gaps where appropriate and ensuring that operators are increasing the detection and remediation of pipeline integrity threats, and mitigating the adverse effects of pipeline failures. On October 18, 2010, PHMSA published an Advanced Notice of Proposed Rulemaking (ANPRM) in the **Federal Register** (75 FR 63774). The ANPRM solicited stakeholder and public input and comments on several aspects of the hazardous liquid pipeline regulations being considered for revision or updating to address various pipeline safety issues.

Subsequently, Congress enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112–90) (2011 Pipeline Safety Act). That legislation included several provisions that are relevant to the regulation of hazardous liquid pipelines. The 2011 Pipeline Safety Act included mandates for PHMSA to complete studies on topics including existing Federal and State regulations for gathering lines, on automatic shutdown and remote control valves, expanding integrity management requirements beyond high-consequence areas, and on the leak detection systems used by hazardous liquid operators. PHMSA completed these studies and submitted the valve and leak detection studies to Congress on December 27, 2012; the gathering line study to Congress on May 8, 2015; and the integrity management (IM) study in April of 2016. These studies are available in the docket for this rulemaking.

Shortly after the 2011 Pipeline Safety Act was passed, the National Transportation Safety Board (NTSB) issued its accident investigation report on the Marshall, MI, accident on July 10, 2012. In it, the NTSB made recommendations regarding the need to revise and update hazardous liquid pipeline regulations. Specifically, the NTSB issued recommendations P–12–03 and P–12–04, which addressed detection of pipeline cracks and ''discovery of condition,'' respectively. The ''discovery of condition'' recommendation would require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.

The Government Accounting Office (GAO) also issued a recommendation in 2012 concerning hazardous liquid and gas gathering pipelines. Recommendation GAO–12–388, dated March 22, 2012, states, ''To enhance the safety of unregulated onshore hazardous liquid and gas gathering pipelines, the Secretary of Transportation should direct the PHMSA Administrator to collect data from operators of federally unregulated onshore hazardous liquid and gas gathering pipelines, subsequent to an analysis of the benefits and industry burdens associated with such data collection.''

On October 13, 2015, PHMSA published a NPRM to seek public comments on proposed changes to the hazardous liquid pipeline safety regulations (80 FR 61609). A summary of those proposed changes is provided later in this document.

Between the publication of the NPRM and this final rule, the President signed the ''Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016'' (PIPES Act of 2016), Public Law 114–183, on June 22, 2016. While the PIPES Act of 2016 contained several mandates that must be addressed through rulemaking, certain provisions are self-executing standards that can be incorporated into this final rule rulemaking without a prior NPRM and opportunity to comment. Those changes are outlined in Section V of this document.

B. Summary of the Major Provisions of the Regulatory Action

In response to these mandates, recommendations, lessons learned, and public input, PHMSA is making certain amendments to the Pipeline Safety Regulations affecting hazardous liquid pipelines. The first and second amendments extend reporting requirements to certain hazardous liquid gravity and rural gathering lines not currently regulated by PHMSA. The collection of information about these lines, including those that are not currently regulated, is authorized under the Pipeline Safety Laws, and the resulting data will assist in determining whether the existing Federal and State regulations for these lines and the scope of their applicability are adequate.

The third amendment requires inspections of pipelines in areas affected by extreme weather or natural disasters that could impose unexpected longitudinal or circumferential pipe loads, or other risks to the pipeline's integrity and continued safe operation. This provision affects all covered lines under § 195.1, whether they be onshore or offshore, and in a high consequence area (HCA) or outside an HCA.[1] Such inspections will help to ensure that operators can safely operate pipelines after these events.

The fourth amendment requires integrity assessments at least once every 10 years, using inline inspection tools or other technology, as appropriate for the threat being assessed, of onshore, piggable, hazardous liquid pipeline segments located outside of HCAs. Existing regulations require operators to assess hazardous liquid pipeline segments located inside HCAs at least once every 5 years. These assessments will provide important information to operators about the condition of these pipelines, including the existence of internal and external corrosion and deformation anomalies.

The fifth amendment extends the required use of leak detection systems beyond HCAs to all regulated hazardous liquid pipelines, except for offshore gathering and regulated rural gathering pipelines. The use of such systems will help to mitigate the effects of hazardous liquid pipeline failures that occur outside of HCAs.

The sixth amendment requires that all pipelines in or affecting HCAs be capable of accommodating in-line inspection tools within 20 years, unless the basic construction of a pipeline cannot be modified to permit that accommodation. In-line inspection tools are an effective means of assessing the integrity of a pipeline and broadening their use will improve the detection of anomalies and prevent or mitigate future accidents in high-risk areas. Finally, PHMSA is clarifying other regulations and is incorporating Sections 14 and 25 of the PIPES Act of 2016 to improve regulatory certainty and compliance.

C. Cost and Benefits

Consistent with Executive Orders 12866 and 13563, PHMSA has prepared an assessment of the benefits and costs of the rule as well as reasonably feasible alternatives. PHMSA estimates that up to 502 hazardous liquid operators may incur costs to comply with the NPRM. The estimated annual costs for individual components of the requirements in this rulemaking range between approximately $5,000 and $10.5 million, with aggregate costs of approximately $19.5 million to $21.4 million for all requirements.[2]

This final rule is primarily designed to mitigate or prevent hazardous liquid pipeline incidents, and is expected to reduce pipeline incident damages, including injuries and fatalities, cleanup and response costs, property damage, product loss, and ecosystem impacts. The rule's information reporting requirements are designed to provide PHMSA information to inform regulatory decision-making. The Regulatory Impact Analysis (RIA) for this final rule is available in the docket. The table below provides a summary of the estimated costs and benefits for each of the eight major provisions and in total (see the RIA for the details of these estimates).

ANNUALIZED COSTS AND BENEFITS BY REQUIREMENT AREA (2017$) [3]

Final rule requirement area	Annual costs [1]		Benefits
	3% discount rate	7% discount rate	
1. Reporting requirements for gravity lines	$5,000	$5,000	Better risk understanding and management.[2]
2. Reporting requirements for gathering lines	$75,000	$76,000	Better risk understanding and management.[3]
3. Inspections of pipelines in areas affected by extreme weather events or natural disasters [4].	Minimal	Minimal	Additional clarity and certainty for pipeline operators.
4. Assessments of onshore pipelines that are not already covered under the IM program using ILI every 10 years [5 6].	$6,467,000	$6,467,000	Avoided incidents and damages through detection of safety conditions.[7]
5. IM repair criteria [8]	$0	$0	$0.
6. LDSs on pipelines located outside HCAs [6]	$8,652,000	$10,508,000	Reduced damages through earlier detection and response.[9]
7. Increased use of ILI tools [10]	Minimal	Minimal	Improved detection of pipeline flaws.[10]
8. Clarify certain IM plan requirements	$4,269,000	$4,343,000	Reduced damages through prevention and earlier detection and response.[11]
Total	$19,468,000	$21,399,000	Reduced damages from avoiding and/or mitigating hazardous liquid releases.

[1] Costs in this table are rounded to the nearest thousand dollars and may differ from costs presented in individual sections of the document. One-time costs are annualized over a 10-year period using discount rates of 3 percent and 7 percent.

[2] Gravity lines can present safety and environmental risks. Depending on the elevation change, a gravity flow pipeline could have more pressure than a pipeline with pump stations to boost the pressure. The benefits of this requirement are not quantified, but based on social costs of $51 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 101 gallons per year to generate benefits that equal the costs.

[1] High Consequence Areas are defined in 49 CFR 195.450.

[2] Estimated costs are annualized using a 7 percent discount rate.

[3] The benefits are not quantified, but based on social costs of $51 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 1,493 gallons per year to generate benefits that equal the costs.

[4] To the extent that the 72-hour timeline required in the final rule results in higher costs for conducting inspections following a disaster (e.g., due to staff overtime), the final rule could result in costs not reflected in this analysis.

[5] PHMSA also conducted a sensitivity analysis that uses alternative baseline assumptions for pipelines not currently covered under the IM program. Specifically, PHMSA estimated the costs for two alternative scenarios: (1) A scenario that assumes that 100 percent of mileage outside HCAs is assessed in the baseline; and (2) a scenario that assumes that 83 percent of the mileage is assessed in the baseline. Costs for these two scenarios are $0 and $12.9 million, respectively.

[6] Excludes gathering lines.

[7] Given a cost per incident of $536,800, incremental assessment of pipelines outside of HCAs would need to prevent 12 incidents for benefits to equate costs.

[8] PHMSA is not finalizing any changes to the repair criteria and as such expects no incremental costs or benefits.

[9] As discussed in Section 2.6.2, 1,918 incidents involved pipelines outside HCAs between 2010 and 2017, or an average of 240 incidents per year. Transmission pipeline incidents outside HCAs had average costs of approximately $382,179, not including additional damages and costs that are excluded or underreported in the incident data. The annual cost estimate is equivalent to the average damages of 28 to 32 such incidents.

[10] Costs (to retrofit pipes to accommodate ILI) and benefits (from avoided damages) would accrue only to the extent that existing practices deviate from industry standards; PHMSA expects costs and benefits will be minimal due to baseline prevalence of ILI-capable pipelines in all areas.

[11] The benefits of reduced costs associated with the prevention or reduction of released hazardous liquids cannot be quantified but could vary in frequency and size depending on the types of failures that are averted. Including additional pipelines in the IM plan, integrating data, and conducting spatial analyses is expected to enhance an operator's ability to identify and address risk. The societal costs associated with incidents involving pipelines in HCAs average $1.7 million per incident (see Section 2.6.2). The annual cost estimates for this requirement are equivalent to the average damages from less than three such incidents. This is relative to an annual average of 161 incidents in HCAs between 2010 and 2017.

II. Background

A. Detailed Overview

This final rule addresses the requirements established by Congress in the 2011 Pipeline Safety Act, which are consistent with the emerging needs of the Nation's hazardous liquid pipeline system. This final rule also advances an important safety need to adapt and expand risk-based safety practices considering changing markets and a growing national population whose location choices are in ever-closer proximity to existing pipelines.

This final rule strengthens protocols for IM, including protocols for inspections, and improves and streamlines information collection to help drive risk-based identification of the areas with the greatest safety deficiencies.

Hazardous Liquid Infrastructure Overview

There are two major types of pipelines along the petroleum transportation route: Gathering pipeline systems, and crude oil and refined products pipeline systems. The location, construction and operation of these systems are generally regulated by Federal and State requirements.

Gathering lines are typically smaller pipelines no more than 8⅝ inches in diameter that transport petroleum from onshore and offshore production facilities. Hazardous liquid pipelines transport the crude oil from the gathering systems to refineries and from refineries to distribution centers. Hazardous liquid lines transport both crude and refined products, and can be hundreds of miles long. These lines may cross State and continental borders, and range in size from 2 to 48 inches in diameter. Hazardous liquid pipeline networks also include pump stations, which move the product through the pipelines, and storage terminals. Changes in product demand has also led to efforts by operators to increase pipeline capacity through flow-direction reversals or converting natural gas pipelines into hazardous liquid pipelines.

Per PHMSA's database, 43 percent of all hazardous liquid pipelines were installed prior to 1970.[4] However, pipeline manufacturing, construction, and operational and maintenance practices have been improving steadily in recent decades, and some older pipes are susceptible to certain manufacturing or construction defects. For example, low-frequency electric resistance welded (ERW) pipe used from the early 1900s through the post-World War II construction boom that lasted well into the 1970s is vulnerable to seam-quality issues. Since the early 1970s, many improvements in pipe manufacturing and materials have been made, and steel and seam properties of pipe have improved with the increased use of high-frequency electric welded (HF–ERW), submerged arc welded (SAW), and seamless pipe (SMLS).[5] In addition, smart pigs, which are tools that record information about the internal conditions of a pipeline, were not developed until the 1960s and 1970s prior to the adoption of the part 195 regulations.

Since 2012, U.S. oil production has increased about 70 percent from approximately 2.4 to 3.4 Billion barrels annually [6] resulting in the United States becoming the world's largest producer of liquid fuels in early 2014. Much of the recent increases in production have been in tight oil plays. Tight oil shale formations are heterogeneous and vary widely over relatively short distances and are subjected to fracking. Examples of tight oil formations include the Bakken Shale, the Niobrara Formation, Barnett Shale, and the Eagle Ford Shale in the United States. Per data from the U.S. Energy Information Administration (EIA), in 2017, tight oil plays accounted for approximately half of the U.S. production, balancing declining production in older plays. While tight oil from shale plays has historically been more difficult to extract, improvements in drilling and production methods, such as horizontal drilling and hydraulic fracturing, have made it economically recoverable. These tight oil plays are located both in regions that have had an oil extraction industry for decades and new regions, such as the Bakken region in North Dakota and Montana, that were not previously oil-producing areas. This has expanded U.S. refiners' access to domestically produced crudes, and U.S. crude oil imports dropped by 7 percent since 2012.[7] Additionally, exports have risen from minimal amounts in 2012 to

[3] Numbers in this table may not sum due to rounding.

[4] PHMSA's Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems; *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[5] HF–ERW steel pipe has a welded pipe seam made using a high frequency welding current. SMLS steel pipe has no longitudinal weld seam. SAW steel pipe has a weld seam made using a submerged welding arc in a bed of powdered flux to shield it from impurities.

[6] U.S. Energy Information Administration, Crude Oil Production. Producers extracted 2.4 billion barrels of crude oil from U.S. fields in 2012 and 3.4 billion barrels of crude oil in 2017. *https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.*

[7] EIA, U.S. Imports of Crude Oil (Thousands of Barrels per Day). *https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbblpd_a.htm.*

over a million barrels per day in 2017.[8] These supply increases and spatial changes in production patterns are creating wide-ranging impacts on liquid fuels transportation infrastructure.

Regulatory History

Congress established the current framework for regulating the safety of hazardous liquid pipelines in the Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979 (Pub. L. 96–129). The HLPSA provides the Secretary of Transportation (the Secretary) with the authority to prescribe minimum Federal safety standards for hazardous liquid pipeline facilities. That authority, as amended in subsequent reauthorizations, is currently codified in the Pipeline Safety Laws (49 U.S.C. 60101, *et seq.*).

PHMSA is the agency within DOT that administers the Pipeline Safety Laws. PHMSA has issued a set of comprehensive safety standards for the design, construction, testing, operation, and maintenance of hazardous liquid pipelines. Those standards are codified in the Hazardous Liquid Pipeline Safety Regulations (49 CFR part 195).

Part 195 applies broadly to the transportation of hazardous liquids or carbon dioxide by pipeline, including on the Outer Continental Shelf, with certain exceptions set forth by statute or regulation. A combination of prescriptive and management-based safety standards is used (*i.e.,* an objective is specified, but the method of achieving that objective is not). Risk management principles play a key role in the IM requirements.

PHMSA exercises primary regulatory authority over interstate hazardous liquid pipelines, and the owners and operators of those facilities must comply with safety standards in part 195. States may apply to PHMSA for a certification to conduct inspections of intrastate hazardous liquid pipelines. Public utility commissions administer most State pipeline safety programs. These State authorities must adopt the Pipeline Safety Regulations as part of a certification or agreement with PHMSA, but may establish more stringent safety standards for intrastate pipeline facilities within their State regulatory authorities. PHMSA is precluded from regulating the safety standards or practices for an intrastate pipeline facility if a State is currently certified to regulate that facility. States certified to regulate their intrastate lines can also enter into agreements with PHMSA to serve as an agent for inspecting interstate facilities, and they can receive Federal monetary grants to off-set the costs of those State inspections.

In 2000 and 2002, the Office of Pipeline Safety (OPS) published regulations requiring IM programs for hazardous liquid pipeline operators in response to a hazardous liquid incident in Bellingham, WA, in 1999 that killed three people.[9] The regulations were broad-reaching and supplemented PHMSA's prescriptive safety requirements with performance and process-oriented requirements. The approach aimed to set expectations for operators while giving them a degree of flexibility in how they complied with those expectations. The objectives of the IM regulations were to accelerate and improve the quality of integrity assessments conducted on pipelines in areas with the highest potential for adverse consequences; promote a more rigorous, integrated, and systematic management of pipeline integrity and risk by operators; strengthen the government's role in the oversight of pipeline operator integrity plans and programs; and increase the public's confidence in the safe operation of the Nation's pipeline network.

In January 2011, PHMSA published the Hazardous Liquid Integrity Management Progress Report,[10] which reported on PHMSA's progress in achieving the program objectives and examined accident trends. The report found that the IM rule and PHMSA's rigorous oversight of operator compliance with the rule are contributing to improved safety performance, including a reduction in the frequency of significant accidents and a decrease in volume spilled in significant accidents.

PHMSA's Progress on Integrity Management

The original part 195 Pipeline Safety Regulations were not designed with risk management in mind. In the mid-1990s, following models from other industries such as nuclear power, PHMSA started to explore whether a risk-based approach to regulation could improve safety of the public and the environment. During this time, PHMSA found that many operators were performing forms of IM that varied in scope and sophistication but there were not consistent minimum standards or requirements.

Since the implementation of the IM regulations more than 15 years ago, many factors have changed. Most importantly, there have been sweeping changes in the oil industry, and the Nation's relatively safe but aging pipeline network faces increased pressures from these changes. Long-identified pipeline safety issues, some of which IM set out to address, remain problems. Infrequent but severe accidents indicate that some pipelines continue to be vulnerable to failures stemming from, among other things, outdated construction methods or materials. Some severe pipeline accidents have occurred in areas outside HCAs where the application of IM principles is not required.[11]

The current IM program is both a set of regulations and an overall regulatory approach to improve pipeline operators' ability to identify and mitigate the risks to their pipeline systems. On the operator level, an IM program includes adopting procedures and processes to identify HCAs, which are areas with the greatest population density and environmental sensitivity; determining likely threats to the pipeline within the HCA; evaluating the physical integrity of the pipe within the HCA; and repairing or remediating any pipeline defects found. Because these procedures and processes are complex and interconnected, effective implementation of an IM program relies on continual evaluation and data integration.

Operators have made great progress towards achieving the IM objectives. Operators have an improved understanding of the precise locations of their HCAs—those areas where integrity assessments and other protective measures spelled out in the IM rule must be taken to assure public safety and environmental protection. During an incident, petroleum can spread over large areas and cause environmental damage. The IM protections for HCAs are designed to account for the potential environmental and community risks from oil releases. Per PHMSA's hazardous liquid annual

[8] EIA, U.S. Exports of Crude Oil (Thousand Barrels per Day). *https://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS–Z00_mbblpd_a.htm.*

[9] 65 FR 75378; December 1, 2000; Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline). 67 FR 1650; January 14, 2002; Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Repair Criteria). 67 FR 2136; January 16, 2002; Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With Less Than 500 Miles of Pipelines).

[10] *http://primis.phmsa.dot.gov/iim/IM_Jan2011_StatusReport_01_23_11.pdf.*

[11] Per PHMSA annual report data accessed May 14, 2019, 1677 non-HCA accidents have occurred since 2010. Of these accidents, 908 resulted in a ''large'' spill, which for reporting purposes is defined as those spills where there was a fatality, injury, fire, explosion, water contamination, property damage of greater than $50,000, or an unintentional loss of product greater than 210 gallons (5 bbls).

data, 42 percent of the Nation's hazardous liquid pipelines [12] can potentially affect HCAs and thus receive the enhanced level of integrity assessment and protection mandated by the IM rule. As required by the IM rule, operators have also conducted baseline integrity assessments on all pipelines that could affect HCAs and have begun conducting reassessments of these same pipeline segments. Through this requirement to assess their pipelines, operators now have an improved understanding of the condition of pipelines in these safety-sensitive areas.

According to PHMSA's January 2011 Hazardous Liquid Integrity Management Progress Report, which tracked the progress and effectiveness of the IM program in its first decade, as a result of these initial baseline assessments, operators have made more than 7,600 repairs of anomalies that required immediate attention, remediated over 28,000 other conditions on a scheduled basis, and addressed an additional 79,000 anomalies that were not required to be addressed by the IM rule, thus significantly improving the condition of the Nation's pipelines.

However, based on recent accidents and mandates from the 2011 Pipeline Safety Act, improvement is still needed in the areas of data integration and their use in risk modelling, risk analysis, and to identify and implement additional preventive and mitigative measures to reduce risk. Improving data integration is critical, as the integrity assessment provisions of the rule only address some of the causes of pipeline failures.

Inadequate Leak Detection, Exposure to Weather, Increased Use, and Age Can Increase the Risk of Pipeline Incidents

Risk factors for pipeline safety issues stem from many sources, including manufacturing issues, external weather and environmental factors, land-use activities near pipelines, other operational issues, and age-related integrity issues.

On July 25, 2010, a segment of a 30-inch-diameter pipeline called Line 6B, owned and operated by Enbridge Incorporated, ruptured in a wetland area in Marshall, MI. Per §§ 195.450 and 195.6, this area was identified by the operator as an "other populated area," which meant it was within an HCA. Per the NTSB's Pipeline Accident Report on the incident, the rupture occurred during the last stages of a planned shutdown and was not discovered or addressed for over 17 hours. During the time lapse, Enbridge twice pumped additional oil (81 percent of the total release) into Line 6B during two startups; the total release was estimated by Enbridge to be 843,444 gallons of crude oil.[13] The oil saturated the surrounding wetlands and flowed into the Talmadge Creek and the Kalamazoo River. In all, 4,632 acres of land were impacted, 346 animals were killed, 4,208 animals were oiled, and fish and benthic invertebrate communities were impacted. Further, approximately 100,000 recreational user-days were lost, including activities like fishing and boating, and general shoreline park and trail use. The incident also resulted in losses of tribal use, as the Kalamazoo River is used by two tribes for water travel; subsistence; and medicinal, economic, educational, and ceremonial services.[14] This incident motivated a reexamination of hazardous liquid pipeline safety. The NTSB made recommendations to PHMSA and the regulated industry regarding the need to improve hazardous liquid pipeline safety. Congress also directed PHMSA to reexamine many of its safety requirements, including the expansion of IM regulations to more hazardous liquid pipelines. Other recent accidents, including a pair of related failures that occurred in 2010 on a crude oil pipeline in Salt Lake City, UT, corroborated the significance of having an adequate means for identifying and responding to leaks in all locations.

The Nation's pipeline system also faces significant risk from failure due to extreme weather events and natural disasters, such as hurricanes, floods, mudslides, tornadoes, and earthquakes. On January 17, 2015, a breach in the Bridger Pipeline Company's Poplar system resulted in a spill into the Yellowstone River near the town of Glendive, MT, releasing 31,835 gallons (758 barrels) [15] of crude oil into the river and affecting local water supplies. Information indicated over 100 feet of pipeline was exposed on the river bottom, and the release point was near a girth weld. A depth of cover survey indicated sufficient cover in late 2011,[16] but the area experienced localized flooding in early 2014. A previous crude oil spill into the Yellowstone River in 2011 near Laurel, MT, was caused by channel migration and river bottom scour, leaving a large span of the pipeline exposed to prolonged current forces and debris washing downstream in the river. Those external forces damaged the exposed pipeline.

In October 1994, flooding along the San Jacinto River led to the failure of eight hazardous liquid pipelines and undermined a number of other pipelines. The escaping products were ignited, leading to 547 people in the area suffering extensive smoke inhalation or burn injuries.[17] According to PHMSA's Accident and Incident Data for hazardous liquid pipelines, from 2010 to 2017, there were 145 reportable incidents [18] in which storms or other severe natural force conditions damaged pipelines and resulted in their failure. Operators reported total damages of over $232 million from these incidents.[19] PHMSA has issued several Advisory Bulletins to operators warning about extreme weather events and the consequences of flooding events, including river scour and river channel migration. Further, in December 2017, the American Petroleum Institute issued a Recommended Practice 1133 that provided guidance to operators on how to identify at-risk river crossings and take measures to reduce such risks before, during, and after flooding- and river-scour events.

In addition to external weather and environmental threats, changing production and shipment patterns are increasing stress on the Nation's

[12] *http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.*

[13] National Transportation Safety Board: "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010," Accident Report NTSB/PAR–12/01, adopted 2012; *http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf.*

[14] U.S. Fish and Wildlife Service: "Final Damage Assessment and Restoration Plan/Environmental Assessment for the July 25–26, 2010 Enbridge Line 6B Oil Discharges near Marshall, MI;" Sections 1.4—Summary of Natural Resource Injuries and 3.0—Injury Assessment and Quantification. October 2015. *https://www.fws.gov/midwest/es/ec/nrda/MichiganEnbridge/pdf/FinalDARP_EA_EnbridgeOct2015.pdf.*

[15] PHMSA Database: "Operator Information: Incident and Mileage Data: Bridger Pipeline LLC," *http://primis.phmsa.dot.gov/comm/reports/operator/OperatorIM_opid_31878.html?nocache=4851%20-%20_Incidents_tab_3#_OuterPanel_tab_2.*

[16] PHMSA, Corrective Action Order, CPF No. 5–2015–5003H, page 4, January 23, 2015; *http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/520155003H_Corrective%20Action%20Order_01232015.pdf.*

[17] NTSB, Pipeline Special Investigation Report, "Evaluation of Pipeline Failures During Flooding and of Spill Response Actions, San Jacinto River Near Houston, Texas, October 1994;" NTSB/SIR–96/04, Adopted September 6, 1996.

[18] Reporting thresholds for hazardous liquid pipelines are established at § 195.50. Operators must report any failures of a hazardous liquid pipeline resulting in any of the following: (1) An explosion or fire not intentionally set by the operator, (2) A release of 5 gallons or more of hazardous liquid or carbon dioxide, (3) The death of an individual, (4) Personal injury requiring hospitalization, (5) Estimated property damage exceeding $50,000.

[19] PHMSA Hazardous Liquid Accident Reports. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.*

pipeline system. Shifting production to tight oil production like shale plays have changed U.S. oil production locations, as well as the types of crude transported in the Nation's pipelines. The U.S. pipeline system has previously moved crude oil from interior production regions to the Gulf of Mexico refineries, and petroleum products from Gulf Coast refineries to the interior of the country. However, increased tight oil production requires significant infrastructure expansion in new areas, and shifting production areas are changing the patterns of oil transport. Many operators are adapting their systems to move crude oil to markets formerly dependent on imports by modifying existing pipelines. These modifications can be made by reversing flow directions and repurposing natural gas pipelines; in some cases pipeline expansion projects can also increase pumping capability with minimal alterations of the pipeline itself.

Reversing a pipeline's flow, modifying pump station placement and operation, changing commodities, or making other changes to a pipeline's historical hydraulic gradient can impose new stresses on the system due to altered pressure gradients, cycling, and flow rates. Furthermore, certain commodities and low flow rates may create new risks of internal corrosion. Occasional failures on hazardous liquid pipelines have occurred after operational changes that include flow reversals and product changes. PHMSA has noticed several recent or proposed flow reversals and product changes on a number of hazardous liquid and gas transmission lines. In response to this phenomenon, on September 18, 2014, PHMSA issued an Advisory Bulletin [20] notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline.

Data indicate that some pipelines also continue to be vulnerable to issues stemming from outdated construction methods or materials. Much of the older pipe in the Nation's pipeline infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process.[21] Such defects cause the pipe to be susceptible to developing hook cracks or other anomalies that may, over time, lead to failures if they are not timely repaired. For example, line pipe manufactured using low-frequency electric resistance welding is susceptible to seam failure. A substantial amount of this type of pipe is still in service; per PHMSA's ''Miles by Decade of Installation Inventory Reports'' for hazardous liquid lines, there were 92,271 miles of pre-1970s pipe still in service in 2017.[22] The IM regulations include specific requirements for evaluating such pipe if located in HCAs, but infrequent-yet-severe failures that are attributed to longitudinal seam defects continue to occur. Per PHMSA's Accident and Incident database, between 2010 and 2017, 84 reportable incidents were attributed to seam failures, resulting in over $220 million of property damage.[23,24]

In the final rule, PHMSA strengthens the IM requirements to identify and respond to the increased pipeline risks resulting from operational changes, weather and associated geotechnical hazards, and increased use and age of a pipe.

Enhanced Collection of Data

To keep the public safe and to protect the Nation's energy security and reliability, operators and regulators must have an intimate understanding of their entire pipeline system, including threats and operations. However, with operators who are not required to report certain information on certain currently unregulated pipelines, and with aging pipelines that are not modernized for internal inspection, there continue to be data gaps that make it hard to fully understand the extent of the potential safety risks to the integrity of the Nation's pipeline system.

PHMSA's regulations exempt rural gathering pipelines and gravity pipelines. Gravity pipelines carry product by means of gravity, and many gravity lines are short and within tank farms or other pipeline facilities. However, some gravity lines are longer and can build up high pressures. PHMSA is aware of gravity lines that traverse long distances with significant elevation changes, which could have significant consequences in the event of a release. Both gravity and gathering lines are currently excluded from reporting requirements, leaving large gaps in PHMSA's knowledge of these unregulated pipeline systems. This is especially true because much of operators' and PHMSA's data is obtained through testing and inspection under IM requirements, which are not currently required for gathering and gravity lines.

To assess a pipeline's integrity, operators generally choose between three methods of testing a pipeline: In-line inspection (ILI), pressure testing, and direct assessment (DA). In 2017, PHMSA estimates that slightly over 90 percent of the hazardous liquid line mileage in HCAs is already piggable and almost 90 percent of these lines were being inspected with ILI tools.

Operators perform ILIs by using special tools, sometimes referred to as ''smart pigs,'' which are usually pushed through a pipeline by the pressure and flow rate of the product being transported. As the tool travels through the pipeline, it identifies and records potential pipe defects or anomalies. Because these tests can be performed with product in the pipeline, the pipeline does not have to be taken out of service for testing to occur, which can reduce cost to the operator and possible service disruptions to consumers. Further, ILI is a non-destructive testing technique, and it can be less costly on a per-unit basis to perform than other assessment methods. However, a very small portion of hazardous liquid pipe segments cannot be inspected through ILI because they are too short in length, which makes getting accurate ILI tool results impractical due to tool speed variations. Other hazardous liquid pipelines might not be inspected through ILI because they do not have enough operating pressure or flow rate to run the tool.

Pipeline operators typically use pressure tests to determine the integrity (or strength) of the pipeline immediately after construction and before placing the pipeline in service. In a pressure test, a test medium (typically water) inside the pipeline is pressurized to a level greater than the normal operating pressure of the pipeline. This test pressure is held for a number of hours to ensure there are no leaks in the pipeline.

Direct assessment is the evaluation of various locations on a pipeline for corrosion threats. Operators will review operational records and indirectly inspect the pipeline with coating surveys, such as close interval, direct

[20] PHMSA: ''Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service'' *Advisory Bulletin,* 79 FR 56121, September 18, 2014; *http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Advisory%20Notices/ADB-2014-04_Flow_Reversal.pdf.*

[21] See *https://primis.phmsa.dot.gov/comm/FactSheets/FSPipeManufacturingProcess.htm* for more information about pipe manufacturing processes and known latent defects.

[22] PHMSA's Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems; *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[23] PHMSA Hazardous Liquid Accident Reports. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.*

[24] The data can be narrowed down by selecting the ''hl2010toPresent'' Excel spreadsheet. Cell ''CR'' indicates the identified location of the failure and whether the failure was in the pipe body or in the pipe seam. If it was identified as a pipe seam failure, Cells ''CW'' and ''CX'' provide additional information on pipe seam type and pipe seam details, respectively.

current voltage gradient, and alternating current voltage gradient surveys, to detect areas where the protective, anti-corrosion coating applied to a pipeline may be faulty, as corrosion may be more likely in these locations. Operators subsequently excavate and examine areas that are likely to have suffered from corrosion. DA can be costly to use without targeting specific locations. A limited number of specific locations, however, may not give an accurate representation of the condition of lengths of entire pipeline segments.

Ongoing research appears to indicate that ILI and hydrostatic pressure ''spike'' testing are more effective than DA for identifying pipe conditions related to cracking defects such as dents with stress cracks, stress corrosion cracking (SCC), selective seam weld corrosion (SSWC), and other seam-type cracking.[25] Hydrostatic testing of hazardous liquid pipelines requires testing to at least 125 percent of the maximum operating pressure (MOP) for at least 4 continuous hours and an additional 4 hours at a pressure of at least 110 percent of MOP if the pipe is not visible. If there is concern about pipe cracks that might grow due to pressure cycling, operating stress levels, environmental conditions, and fatigue, then a spike test at a pressure of up to or over 139 percent of MOP for a short period (up to a 30-minute hold time or longer) may be conducted. A spike test detects pipe body and seam cracks by causing any cracks that would later grow to failure to fail during the hydrostatic test. Both regulators and operators have expressed interest in improving ILI methods as an alternative to hydrostatic testing for better risk evaluation and management of pipeline safety. Hydrostatic pressure testing can result in substantial costs and occasional disruptions in service, whereas ILI testing can obtain data that is not otherwise obtainable via other assessment methods, such as pipe wall loss, dents, and cracking.

In this final rule, PHMSA is addressing data gaps and increasing the quality of data collected by expanding the reporting requirements to cover both gathering and gravity lines and requiring that all lines in HCAs be piggable for a better understanding of pipeline characteristics. The final rule will also require operators to fully integrate their pipeline data across all data sources to close any remaining gaps.

Looking at Risk Beyond HCAs

In addition to improving IM programs for the pipe that they already cover, PHMSA understands the importance of carefully reconsidering the scope of the areas covered by IM requirements. While PHMSA's hazardous liquid IM program manages risks primarily by focusing oversight on areas with the greatest population density and environmental sensitivity, it is imperative to protect the safety of environmental resources and communities throughout the country. The changing landscape of production, consumption, and product movement merits a fresh look at the current scope of IM coverage.

The current definition of an HCA uses Census Bureau definitions of urbanized areas or areas with a concentrated population.[26] The HCA definition also encompasses ''unusually sensitive areas,'' including drinking water or ecological resource areas and commercially navigable waterways. However, liquid spills, even outside HCAs, can result in environmental damage necessitating clean up, restoration costs, and lost use and non-use values. If operators do not periodically assess and repair their pipelines, liquid spills are more likely to occur. In fact, devastating incidents have occurred outside of HCAs in rural areas where populations are sparse, and operators have not been required to assess their lines as frequently as lines covered by IM. Per PHMSA's databases, between 2010 and 2017, significant incidents at hazardous liquid facilities accounted for over 993,097 barrels spilled, 24 injuries, and 10 fatalities. Out of those, over 702,091 barrels spilled, 10 injuries, and four fatalities occurred in non-HCA areas.[27] These data show that ruptures with the potential to affect populations, the environment, or commerce, can occur anywhere on the Nation's pipeline system.

If constant improvement and zero incidents are goals for pipeline operators,[28] extending and prioritizing IM assessments and principles to all parts of pipeline networks is an effective way to achieve those goals. Extending IM assessments and principles to non-HCAs will help clarify vulnerabilities and prioritize improvements, and this final rule takes important steps towards developing that approach and will lead operators to gather valuable information they may not have collected if regulations were not in place.

In this final rule, PHMSA is requiring operators to assess onshore, piggable pipelines outside of HCAs periodically using ILI or other technology, if appropriate, to detect (and remediate) anomalies in all locations within their pipeline systems. PHMSA is providing operators with deadlines to verify their segment analyses to identify any new HCAs and implement the appropriate actions. These changes would ensure the remediation of anomalous conditions that could potentially impact people, property, or the environment, while at the same time allowing operators to allocate their resources based on pipeline risks and the vulnerability of surrounding areas.

Recent Developments in Hazardous Liquid Pipeline Safety Regulation

On October 18, 2010, PHMSA posed a series of questions to the public in the context of an ANPRM titled ''Pipeline Safety: Safety of On-Shore Hazardous Liquid Pipelines'' (75 FR 63774). In that document, PHMSA sought comments on several proposed changes to part 195, including: (1) The scope of part 195 and existing regulatory exceptions, (2) Criteria for designation of HCAs, (3) Leak detection and emergency flow restricting devices, (4) Valve spacing, (5) Repair criteria outside of HCAs, and (6) Stress corrosion cracking. The questions in this ANPRM considered topics relating to the statutory mandates; the post-Marshall, MI, NTSB and GAO recommendations; and other pipeline safety mandates. Twenty-one organizations and individuals submitted comments in response to the ANPRM.

PHMSA reviewed the received comments, the 2011 Pipeline Safety Act,

[25] See: Comprehensive Study to Understand Longitudinal ERW Seam Research & Development study task reports: Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), Report No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5), which can be found online at: *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.*

[26] Specifically, § 195.450 states that a *high population area* is an urban area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile, and an *other populated area* is a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

[27] PHMSA Hazardous Liquid Accident Reports. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.*

[28] Major trade associations, including API and INGAA, have publicly committed to a goal of zero incidents. See: *https://www.api.org/oil-and-natural-gas/wells-to-consumer/transporting-oil-natural-gas/pipeline/pipeline-safety* and *https://www.ingaa.org/File.aspx?id=20463 for more details.*

and the NTSB and GAO recommendations, and responded in the subsequent NPRM published on October 13, 2015, (80 FR 61609). In summary, the NPRM addressed the following areas: (1) Reporting requirements for gravity lines, (2) Reporting requirements for gathering lines, (3) Inspections of pipelines following extreme weather events and natural disasters, (4) Periodic assessments of pipelines not subject to IM, (5) Repair criteria, (6) Expanded use of leak detection systems, (7) Increased use of in-line inspection tools, and (8) Clarifying other requirements. A summary of comments and responses to those comments are provided later in the document. The ANPRM and NPRM may be viewed at *http://www.regulations.gov* by searching for Docket No. PHMSA–2010–0229.

B. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

After the issuance of the ANPRM on October 18, 2010, the 2011 Pipeline Safety Act included several statutory requirements related directly to the topics being considered in the ANPRM. The related topics and statutory citations that PHMSA considered within the context of this rulemaking include, but are not limited to:

- Section 5(f)—Requires, if appropriate, regulations issued by the Secretary to expand integrity management system requirements, or elements thereof, beyond high-consequence areas. These regulations are to be dependent on an evaluation and report of whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas;
- Section 8—Requires, if appropriate, regulations regarding leak detection on hazardous liquid pipelines and establishing leak detection standards. These regulations are to be dependent on a report on the analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies, and an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems;
- Section 14—Permits PHMSA to issue regulations for pipelines transporting non-petroleum fuels, such as biofuels;
- Section 21—Requires a review on the regulation of Gas (and Hazardous Liquid) Gathering Lines and the issuance of further regulations, if appropriate; and
- Section 29—Requires that operators consider seismicity when evaluating pipeline threats.

C. National Transportation Safety Board Recommendation

On July 10, 2012, shortly after the 2011 Pipeline Safety Act was passed, the NTSB issued its accident investigation report on the Marshall, MI, accident. In it, the NTSB made additional recommendations to update the hazardous liquid pipeline regulations. Pertaining directly to this rule, the NTSB issued recommendation P–12–04, which addressed the ''discovery of condition'' as follows:

- NTSB Recommendation P–12–4: ''*Revise Title 49 Code of Federal Regulations 195.452(h)(2), the 'discovery of condition,' to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify the Pipeline and Hazardous Materials Safety Administration and provide an expected date when adequate information will become available.*''

D. Summary of Each Topic

This final rule amends the Federal Pipeline Safety Regulations to address the following topics. Details of the changes in this rule are discussed in this document in Section IV, ''Analysis of Comments and PHMSA Response,'' and Section V, ''Section-by-Section Analysis.''

(1) Extend Certain Reporting Requirements to Certain Gravity and Rural Hazardous Liquid Gathering Lines

Gravity lines are pipelines that carry product by means of gravity and are currently exempt from PHMSA regulations. Many gravity lines are short and within tank farms or other pipeline facilities; however, some gravity lines are longer and can build up large amounts of pressure. Further, certain gravity lines may have significant elevation changes, which can lead to serious consequences in the event of a release.

For PHMSA to effectively analyze the safety performance and risk of gravity lines, PHMSA needs basic data about those pipelines. The agency has the statutory authority to gather data for all gravity lines (49 U.S.C. 60117(b)). Accordingly, PHMSA is amending the Pipeline Safety Regulations (PSR) to require that the operators of certain gravity lines comply with requirements for submitting annual, safety-related condition, and incident reports. PHMSA estimates that, at most, five hazardous liquid pipeline operators will be affected. Based on comments to the ANPRM from the American Petroleum Institute and the Association of Oil Pipelines (API–AOPL), 3 operators have approximately 17 miles of gravity-fed pipelines. PHMSA estimated that proportionally 5 operators would have 28 miles of gravity-fed pipelines.

PHMSA is also amending the PSR to extend the annual, accident, and safety-related condition reporting requirements of part 195 to all hazardous liquid gathering lines. The Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 96–129) did not mandate the regulation of rural gathering lines because at that time they were not thought to present a significant enough risk to public safety to justify Federal regulation based on the data available at that time. However, the Pipeline Safety Act of 1992 (Pub. L. 102–508) authorized the issuance of safety standards for regulated rural gathering lines based on a consideration of certain factors and subject to certain exclusions. When PHMSA adopted the current requirements for regulated rural gathering lines, the agency made judgments in implementing those statutory provisions based on the information available at that time.

Recent data indicates, however, that PHMSA regulates less than 4,000 miles of the approximately 30,000 to 40,000 miles of onshore hazardous liquid gathering lines in the United States.[29] That means that about 90 percent of the onshore gathering line mileage is not currently subject to any minimum Federal pipeline safety standards. The NTSB has also raised concerns about the safety of hazardous liquid gathering lines in the Gulf of Mexico and its inlets,[30] which are only subject to certain inspection and reburial requirements.

In the ANPRM, PHMSA asked whether the agency should repeal or modify any of the exceptions for hazardous liquid gathering lines. Section 195.1(a)(4)(ii) states that part 195 applies to a ''regulated rural gathering line as provided in § 195.11.'' PHMSA published a final rule on June 3, 2008 (73 FR 31634), that prescribed certain safety requirements for regulated rural gathering lines (*i.e.,* the filing of accident, safety-related condition, and annual reports; establishing the MOP in accordance with § 195.406; installing line markers; and establishing programs for public awareness, damage prevention, corrosion control, and operator qualification of personnel).

The June 2008 final rule did not establish safety standards for all rural hazardous liquid gathering lines. Some of those lines cannot be regulated by statute (*i.e.,* 49 U.S.C. 60101(b)(2)(B) states that ''the definition of ''regulated gathering line'' for hazardous liquid may not include a crude oil gathering line that has a nominal diameter of not more than 6 inches, is operated at low pressure, and is in a rural area that is not unusually sensitive to environmental damage''), and Congress did not remove this exemption in the 2011 Pipeline Safety Act.

PHMSA is currently statutorily limited to regulating gathering lines in HCAs and ''regulated rural gathering lines,'' which are defined in § 195.11 to mean onshore gathering lines in a rural area that meet certain criteria (*i.e.,* has a nominal diameter from 6⅝ in. (168 mm) to 8⅝ in. (219.1 mm), is in or within ¼ mile of an unusually sensitive area as defined in § 195.6, and operates at a maximum pressure established under § 195.406). This limitation leaves gaps in the regulation of rural gathering lines not classified as regulated rural gathering lines.

Further, PHMSA currently collects no data on unregulated gathering lines. This lack of data prevents PHMSA from being able to determine whether current regulations should be applied to currently unregulated gathering lines. Therefore, in this final rule, PHMSA is requiring reporting on all hazardous liquid gathering lines and will consider, based on the nature of the data gathered, the appropriateness of additional regulatory requirements, if any, for hazardous liquid gathering lines in the future.

The final rule, however, does not address or require data collection for transportation-related flow lines until further study and cost analyses can be conducted. PHMSA notes that, per Section 12 of the 2011 Pipeline Safety Act, Congress has provided PHMSA with the authority to collect data on pipelines transporting oil off the grounds of the well where it originated and across areas not owned by the producer, regardless of the extent to which the oil has been processed, if at all. Aside from this rulemaking, PHMSA may consider collecting these data in the future. As discussed above, any decision PHMSA makes to expand its oversight of gathering lines beyond what is currently regulated will be driven by risk assessment and analysis based on evaluations of incident and accident data, data related to infrastructure, and further technological advancements such as the unconventional production practices used in shale formations.

(2) Require Inspections of Pipelines in Areas Affected by Extreme Weather and Natural Disasters

Extreme weather has been a contributing factor in several pipeline failures. For example, in 1994, flooding in Texas led to river scour and ground movement that caused the failure of eight pipelines and the release of more than 35,000 barrels of hazardous liquids into the San Jacinto River. Some of that released product also ignited, causing minor burns and other injuries to nearly 550 people according to the NTSB. In July 2011, a pipeline failure associated with river bottom scour occurred near Laurel, MT, causing the release of an estimated 1,000 barrels of crude oil into the Yellowstone River. That area had experienced extensive flooding due to warm weather causing the rapid melting of large snowpack levels in the weeks leading up to the failure. The operator estimated the cleanup costs at approximately $135 million. In January 2015, another pipeline failure caused by river bottom scour again occurred on the Yellowstone River, spilling approximately 758 barrels of crude oil into the river, causing the shutdown of nearby drinking-water intakes.[31] Additionally, on October 21, 2016, extreme localized flooding, soil erosion, and ground movement caused a release of over 1,238 barrels of gasoline into the Loyalsock Creek in Lycoming County, PA. Further, on March 20, 2018, heavy rain caused a pipeline to rupture and release 1,400 barrels of diesel fuel into Big Creek at Solitude, IN. Specifically, a girth weld on the pipeline ruptured due to land slippage caused by the saturated soil.

Weather events and natural disasters that can cause river scour, soil subsidence or ground movement may subject pipelines to additional external loads, which could cause a pipeline to fail. These conditions can pose a threat to the integrity of pipeline facilities if those threats are not promptly identified and mitigated. While the existing regulations provide for design standards that consider the load that may be imposed by geological forces, events like the ones described above can quickly impact the safe operation of a pipeline and have severe consequences if not mitigated and remediated as quickly as possible.

PHMSA issued Advisory Bulletins in 2015, 2016, and 2019 to communicate the potential for damage to pipeline facilities caused by severe flooding, including actions that operators should consider taking to ensure the integrity of pipelines in the event of flooding, river scour, river channel migration, and earth movement.[32] As PHMSA has noted in a series of Advisory Bulletins, hurricanes are also capable of causing extensive damage to both offshore and inland pipelines (*e.g.,* Hurricane Ivan, September 23, 2004 (69 FR 57135); Hurricane Katrina, September 7, 2005

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[29] PHMSA, ''Hazardous Liquid Pipeline Miles and Tanks,'' *https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?Portalpages&NQUser=PDM_WEB_USER&NQPassword=Public_Web_User1&PortalPath=%2Fshared%2FPDM%20Public%20website%2F_portal%2FPublic%20Reports&Page=Infrastructure&Action=Navigate&col1=%22PHP%20-%20Geo%20Location%22.%22State%20Name%22&val1=%22%22,* retrieved 11/20/2018.

[30] Deborah Hersman, Testimony before the Subcommittee on Surface Transportation and Merchant Marine Infrastructure, Safety, and Security Committee on Commerce, Science, and Transportation, United States Senate Hearing on Ensuring the Safety of our Nation's Pipelines, Washington DC, 6/24/2010. *https://www.ntsb.gov/news/speeches/DHersman/Pages/Testimony_before_the_Subcommittee_on_Surface_Transportation_and_Merchant_Marine_Infrastructure_Safety_and_Security_Committ.aspx.*

[31] *http://deq.mt.gov/Portals/112/DEQAdmin/DIR/Documents/Bridger%20Consent%20Order/Final%20Bridger%20Consent%20Order.pdf?ver=2017-02-09-121902-843.*

[32] ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' April 9, 2015, 80 FR 19114; and January 19, 2016, 81 FR 2943. See also ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' May 2, 2019, 84 FR 18919.

(70 FR 53272); Hurricane Rita, September 1, 2011 (76 FR 54531)).

These events demonstrate the importance of working to ensure that our Nation's waterways and the public are adequately protected from pipeline risks in the event of a natural disaster or extreme weather. PHMSA is aware that many operators perform inspections following such events; however, because it is not a requirement, some operators do not. Therefore, PHMSA is amending the PSR to require that operators commence inspection of their potentially affected assets within 72 hours after the cessation of an extreme weather event such as a hurricane, flood, landslide, earthquake, or other natural disaster that has the likelihood to damage infrastructure. PHMSA would not expect operators to comply with these provisions for weather events when, considering the physical characteristics, operating conditions, location, and prior history of the affected system, the event would not have a likelihood of damage to the pipeline. For example, extreme weather events would not include rain events that do not exceed the high-water banks of the rivers, streams or beaches in proximity to the pipeline; rain events that do not result in a landslide in the area of the pipeline; storms that do not produce winds at tropical storm or hurricane level velocities; or earthquakes that do not cause soil movement in the area of the pipeline.

Under this requirement, an operator must inspect all potentially affected pipeline facilities following these types of events to detect conditions that could adversely affect the safe operation of the pipeline. The operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining whether the event necessitates an inspection as well as the appropriate method for performing the inspection. If the event creates a likelihood that there is damage to pipeline infrastructure, the operator must commence an inspection within 72 hours after the cessation of the event, defined as the point in time when the area can be safely accessed by personnel and equipment, including availability of personnel and equipment, required to perform the inspection. PHMSA has found that 72 hours is reasonable and achievable in most cases based on prior observations of extreme events. If an operator finds an adverse condition, the operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained from the inspection. Such actions might include, but are not limited to:

- Reducing the operating pressure or shutting down the pipeline;
- Isolating pipelines in affected areas and performing ''stand up'' leak tests;
- Modifying, repairing, or replacing any damaged pipeline facilities;
- Preventing, mitigating, or eliminating any unsafe conditions in the pipeline rights-of-way;
- Performing additional patrols, depth of cover surveys, ILI or hydrostatic tests, or other inspections to confirm the condition of the pipeline and identify any imminent threats to the pipeline;
- Implementing emergency response activities with Federal, State, or local personnel; and
- Notifying affected communities of the steps that can be taken to ensure public safety.

This requirement is based on the experience of PHMSA and is expected to increase the likelihood that operators will find and respond to safety conditions more quickly.

(3) Require Assessments of Pipelines That Are Not Already Covered Under the IM Program Requirements at Least Once Every 10 Years

PHMSA is requiring that operators periodically assess onshore, piggable, hazardous liquid pipeline segments in non-HCAs. PHMSA has determined that expanding assessment requirements to these non-HCA pipeline segments will provide operators with valuable information they may not have collected if regulations were not in place. Such a requirement works to ensure prompt detection and remediation of corrosion and other deformation anomalies across the Nation, not just in populated or environmentally sensitive areas as defined by Federal regulations. There is still considerable consequence risk—regarding personal safety, environmental damage, and economic impact—of a spill in less-populated areas, into waterways not designated as ''commercially navigable,'' recreational areas, commercial fishing areas, and agriculturally productive areas that do not meet the definition of an HCA.

In this rulemaking, § 195.416 requires operators to assess onshore, piggable, non-HCA, hazardous liquid pipeline segments at least once every 10 years, which allows operators to prioritize assessments in HCAs over assessments in non-HCAs (the assessment period is 5 years for hazardous liquid pipeline segments that are in or can otherwise affect an HCA). The individuals who review the results of these assessments will need to be qualified by knowledge, training, and experience and will be required to consider any uncertainty in the results obtained, including ILI tool tolerance, when determining whether any conditions could adversely affect the safe operation of a pipeline. Such determinations will have to be made promptly, but no later than 180 days after an inspection, unless the operator demonstrates that the 180-day deadline is impracticable.

Operators are required to comply with the other provisions in part 195 in implementing the requirements in § 195.416. That includes having appropriate provisions for performing these periodic assessments and any resulting repairs in an operator's procedural manual (see § 195.402); adhering to the recordkeeping provisions for inspections, tests, and repairs (see § 195.404); and taking appropriate remedial action under § 195.401(b)(1), as discussed below.

Such requirements will help ensure operators obtain information necessary for the detection and remediation of corrosion and other deformation anomalies in all locations, not just HCAs. Of the many assessment methods, PHMSA has found that ILI in many cases is the most efficient and effective. Operators can perform ILIs while pipelines are in service without any interruption of product flow. Further, ILIs are non-destructive and can provide information beyond direct assessments, which can only tell whether there is exterior coating damage or corrosion, and hydrotests, which are essentially ''pass'' or ''fail.'' ILI tools, which are constantly improving, can provide accurate information on internal corrosion, external corrosion, cracks, and gouges. Additionally, there is robust guidance and documentation for the use of ILI; API and the National Association of Corrosion Engineers (NACE) have developed standards for ILIs that provide guidelines on appropriate tool selection, assessment procedures, and the qualification of personnel conducting assessments.

Currently, operators said they are performing ILI assessments on a large portion of both HCA and non-HCA pipeline mileage, even though no regulation requires them to assess mileage outside of HCAs. Reported repairs in non-HCA segments reflect this indication. PHMSA wants to best ensure that current assessment rates continue and expand to those areas not voluntarily assessed. PHMSA has determined that by adopting these amendments to the existing pipeline safety regulations, data collection will continue to improve across the entire pipeline system, and anomalies that may have previously gone undetected in non-HCAs will be detected and repaired in a more consistent manner.

(4) Expand the Use of Leak Detection Systems for Certain Hazardous Liquid Pipelines

With respect to new hazardous liquid pipelines, PHMSA is amending § 195.134 to require that all new covered pipelines, in both HCAs and non-HCAs, have leak detection systems within 1 year after this final rule is published in the **Federal Register**, and all covered pipelines constructed prior to the rule's publication have leak detection systems within 5 years after this rule is published. Recent pipeline accidents, including related failures that occurred in 2010 on a crude oil pipeline in Salt Lake City, UT; a failure of another crude oil pipeline in Santa Barbara, CA, in 2015; a crude oil release in Belfield, ND, in 2016; and the failure of refined products lines in Dono Ana County, NM, in 2018, corroborate the significance of having an adequate means for identifying leaks in all locations along the pipeline right-of-way. PHMSA, aware of the significance of leak detection, held a 2-day workshop in Rockville, MD, on March 27–28 of 2012.[33] These workshops sought comment from the public concerning many of the issues raised in the 2010 ANPRM, including leak detection expansion. Both workshops were well attended, and PHMSA received valuable input from stakeholders on the technical gaps and challenges for future research and ways to leverage resources to achieve common objectives and reduce duplication of research programs. Participants also discussed the development of leak detection for all pipeline types and the capabilities and limitations of current leak detection technologies.

With respect to existing pipelines, part 195 currently contains mandatory leak detection requirements for only those hazardous liquid pipelines that could affect an HCA. Congress included additional requirements for leak detection systems in section 8 of the 2011 Pipeline Safety Act. That legislation requires the Secretary to submit a report to Congress, within 1 year of the enactment date, on the use of leak detection systems, including an analysis of the technical limitations and the practicability, safety benefits, and adverse consequences of establishing additional standards for the use of those systems. Congress authorized the issuance of regulations for leak detection if warranted by the findings of the report.

PHMSA publicly provided the results of the 2012 Kiefner and Associates study on leak detection systems in the pipeline industry, including the current state of technology. The study found that most leak detection technologies can be retrofitted to existing pipelines, though many operators ''fear investing in leak detection systems, with potentially little benefit to show from them and no way to truly measure success in a standardized way,'' resulting in leak detection being implemented ''cautiously, and incrementally, on measurement and other systems that are already in place.''[34]

Based on information available to PHMSA, including post-accident reviews and the Kiefner Report, the need to expand the use of leak detection systems and strengthen the current leak detection requirements is clear. A robust leak detection system is extremely important to hazardous liquid operators because it triggers all other impact mitigation measures that an operator should plan for, including safe flow shutdown, spill containment, cleanup, and remediation. In this final rule, PHMSA is modifying § 195.444 to require a means for detecting leaks on all portions of a hazardous liquid pipeline system, including non-HCA lines, and to require that operators perform an evaluation to determine what kinds of systems must be installed to adequately protect the public, property, and the environment. The factors that must be considered during that evaluation include (but are not limited to) the characteristics and history of the affected pipeline, the capabilities of available leak detection systems, and the location of emergency response personnel. PHMSA is retaining the requirements in §§ 195.134 and 195.444 that each new computational leak detection system comply with the applicable requirements in API Recommended Practice 1130.[35]

Given the difficulties identified in the Kiefner study related to leak detection performance standards, PHMSA is not making any additional changes to the regulations concerning specific leak detection system performance criteria requirements at this time. PHMSA will be studying this issue further and may make proposals concerning this topic in a later rulemaking.

(5) Increase Accommodation of In-Line Inspection Tools

In this final rule, PHMSA is amending the part 195 regulations to require that all hazardous liquid pipelines in HCAs and areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless subject to PHMSA approval, the basic construction of a pipeline will not accommodate the passage of such a device or the operator determines it would abandon the pipeline because of the cost of complying with the amendment. Per the petition process at § 190.9, operators would be required to document these determinations and submit the documentation to PHMSA for approval.

Modern ILI tools can provide a relatively complete examination of the entire length of a pipeline, including information about threats that other assessment methods cannot always identify. ILI tools also provide superior information about incipient flaws (*i.e.,* flaws that are not yet a threat to pipeline integrity, but that could become so in the future), thereby allowing these conditions to be monitored over consecutive inspections and remediated before a pipeline failure occurs. Hydrostatic pressure testing, another well-recognized method, reveals flaws (such as wall loss and cracking flaws) that cause pipe failures at pressures that exceed actual operating conditions, but only allows operators to determine whether a required safety margin is met (*i.e.,* pass/fail) and does not provide information about the existence of anomalies that could deteriorate over time between tests. Similarly, external corrosion direct assessment (ECDA) is a form of direct assessment that can identify instances where coating damage or ineffective coatings may be affecting pipeline integrity, but operators must perform additional activities, including follow-up excavations and direct examinations, to verify the extent of that threat. ECDA also does not provide information about the internal condition of a pipe to the extent an ILI tool would.

The current regulations for the passage of ILI devices in hazardous liquid pipelines are prescribed in § 195.120, which require that new and replaced pipelines are designed to accommodate ILI tools. The basis for these requirements is a 1988 law that addressed the Secretary's authority with regard to requiring the accommodation

[33] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=75.*

[34] Kiefner and Associates, Inc., ''Final Report on Leak Detection Study-DTPH56–11–D–000001,'' December 10, 2012; *http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Press%20Release%20Files/Leak%20Detection%20Study.pdf.*

[35] API RP 1130 focuses on the design, implementation, testing and operation of Computational Pipeline Monitoring (CPM) systems that use an algorithmic approach to detect hydraulic anomalies in pipeline operating parameters for hazardous liquid pipelines.

of ILI tools. This law required the Secretary to establish minimum Federal safety standards for the use of ILI tools, but only in newly constructed and replaced hazardous liquid pipelines (Pub. L. 100–561).

As the Research and Special Programs Administration (RSPA; a predecessor agency of PHMSA), explained in the final rule published on April 12, 1994 (59 FR 17275), that promulgated § 195.120, ''the clear intent of th[at] congressional mandate [wa]s to improve an existing pipeline's piggability,'' and to ''require the gradual elimination of restrictions in existing hazardous liquid and carbon dioxide lines in a manner that will eventually make the lines piggable.'' RSPA also noted that Congress amended the 1988 law in the Pipeline Safety Act of 1992 (Pub. L. 102–508) to require the periodic internal inspection of hazardous liquid pipelines, including with ILI tools in appropriate circumstances. In 1996, Congress passed another law further expanding the Secretary's authority to require pipeline operators to have systems that can accommodate ILI tools. In particular, Congress provided additional authority for the Secretary to require the modification of existing pipelines whose basic construction would accommodate an ILI tool to accommodate such a tool and permit internal inspection (Pub. L. 104–304). RSPA established requirements for the use of ILI tools in pipelines that could affect HCAs in a final rule published on December 1, 2000 (65 FR 75378).

Section 60102(f)(1)(B) of the Pipeline Safety Laws allows the requirements for the passage of ILI tools to be extended to existing hazardous liquid pipeline facilities, provided the basic construction of those facilities can be modified to permit the use of smart pigs. The current requirements apply only to new hazardous liquid pipelines and to line sections where the line pipe, valves, fittings, or other components are replaced. Exceptions are also provided for certain kinds of pipeline facilities, including manifolds, piping at stations and storage facilities, piping of a size that cannot be inspected with a commercially available ILI tool, and smaller-diameter offshore pipelines.

In this final rule, PHMSA is taking steps to further facilitate the gradual elimination of pipelines that are not capable of accommodating smart pigs in accordance with the authority provided in section 60102(f)(1)(B). PHMSA is limiting the circumstances where a pipeline can be constructed without being able to accommodate a smart pig. Under the current regulation, an operator can petition the PHMSA Administrator for such an allowance for reasons of impracticability, emergencies, construction time constraints, costs, and other unforeseen construction problems. PHMSA believes that an exception should still be available for emergencies and where the basic existing construction of a pipeline makes that accommodation impracticable.

Regulations already require that new and replaced pipelines accommodate ILI tools, and many of the pipelines covered by this new rule will need to be replaced and therefore will accommodate ILI tools before the end of the 20-year implementation period. Providing industry with sufficient time to implement this provision allows the industry to prioritize retrofits and replacements based on age or other factors; it also reduces the mileage of pipeline potentially needing to be replaced before it has reached the limit of its operational life. PHMSA determined that the 20-year timeline strikes the appropriate balance between the need for upgrades with the operational challenges of making these changes.

(6) Clarify Other Requirements

In this final rule, PHMSA is also making several other clarifying changes to the regulations that are intended to improve compliance and enforcement. First, PHMSA is proposing to revise paragraph (b)(1) of § 195.452 to better harmonize this section with other parts of the current regulations. Currently, § 195.452(b)(2) requires that segments of new pipelines that could affect HCAs be identified before the pipeline begins operations, and § 195.452(d)(1) requires that baseline assessments for covered segments of new pipelines be completed by the date the pipeline begins operation. However, § 195.452(b)(1) does not require an operator to draft its IM program for a new pipeline until 1 year after the pipeline begins operation. These provisions are inconsistent, as the identification of could-affect segments and performance of baseline assessments are elements of the written IM program. PHMSA is amending the table in (b)(1) to resolve this issue by eliminating the 1-year compliance deadline for Category 3 pipelines. An operator of a new pipeline is required to develop its written IM program before the pipeline begins operation—there is no burden associated with this amendment because operators already were required to report to DOT prior to construction.

Second, as mentioned in the non-HCA assessment section, operators of both HCA lines and non-HCA lines will have equal requirements for the ''discovery'' of conditions, which occurs when an operator has adequate information about a condition to determine that it presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable. This could include demonstrating why such information would not be available prior to that date. If an operator believes that unique circumstances exist in a particular case that make the 180-day period impracticable, the operator must submit a notification to PHMSA and provide an expected date when adequate information will become available. The submission of such a notification, by itself, will not affect compliance determinations on whether the 180-day requirement was met. PHMSA is thereby amending the existing ''discovery of condition'' language at § 195.452(h)(2) in the pipeline safety regulations to reflect these changes.

A decade's worth of IM inspection experience has shown that many operators are performing inadequate information analyses (*i.e.,* they are collecting information but are not affording it sufficient consideration, or they are not promptly evaluating the information they have gathered following events that have increased risk, such as historic weather events). Ongoing data integration is one of the most important aspects of the IM program, and operators must account for interactions between threats or conditions affecting the pipeline when setting priorities for dealing with identified issues. For example, evidence of potential corrosion in an area with foreign pipeline crossings,[36] nearby current interference from power lines and electrically powered transport systems, evidence of land movement or waterway channel changes that may impact pipeline integrity, and recent aerial patrol indications of excavation activity could indicate a priority for operators to reassess risk and make timely changes to their IM program to reduce that risk. Consideration of each of these factors individually would not necessarily reveal any need for priority attention. PHMSA is concerned that a major benefit to pipeline safety intended in the IM rule is not being realized

[36] Foreign pipelines can include other hazardous liquid, natural gas, water, sewer, or drainage pipelines.

because of inadequate information analyses.

For this reason, PHMSA is adding specificity to paragraph (g) by establishing several pipeline attributes that must be included in these analyses and requiring explicitly that operators integrate analyzed information. PHMSA is also requiring operators to consider explicitly any spatial relationships among anomalous information. PHMSA supports the use of computer-based geographic information systems (GIS) to record this information. GIS systems can be beneficial in identifying spatial relationships, but analysis is required to identify where these relationships could result in situations adverse to pipeline integrity.

Second, PHMSA is requiring operators to verify their pipeline segment identification (as HCAs or otherwise) annually by determining whether factors considered in their analysis have changed. Section 195.452(b) currently requires that operators identify each segment of their pipeline that could affect an HCA in the event of a release, but there is no explicit requirement that operators assure that their identification of covered segments remains current. As time goes by, the likelihood increases that factors considered in the original identification of covered segments may have changed. Construction activities or erosion near the pipeline could change local topography in a way that could cause product released in an accident to travel farther than initially analyzed. Changes in agricultural land use could also affect an operator's analysis of the distance released product could be expected to travel. Changes in the deployment of emergency response personnel could increase the time required to respond to a release and result in a release affecting a larger area if the original segment identification relied on emergency response in limiting the transport of released product. Therefore, PHMSA has determined that operators should periodically re-visit their initial analyses to determine whether they need updating; operators might identify new HCAs in subsequent analyses.

The change that PHMSA is adopting does not automatically require operators to re-perform their segment analyses. Rather, it requires operators to first identify the factors considered in their original analyses, determine whether those factors have changed, and consider whether any such change would likely affect the results of the original segment identification. If so, the operator is required to perform a new segment analysis to validate or change the endpoints of the segments affected by the change.

Further, Section 29 of the 2011 Pipeline Safety Act states that ''[i]n identifying and evaluating all potential threats to each pipeline segment pursuant to parts 192 and 195 of title 49, Code of Federal Regulations, an operator of a pipeline facility shall consider the seismicity of the area.'' While seismicity is already mentioned at several points in the IM program guidance provided in Appendix C of 49 CFR part 195, PHMSA is amending the PSR to further comply with Congress's directive by including an explicit reference to seismicity in the list of risk factors that must be considered in establishing assessment schedules (§ 195.452(e)), performing information analyses (§ 195.452(g)), and implementing preventive and mitigative measures (§ 195.452(i)) under the IM requirements.

Finally, the PIPES Act of 2016 contained two sections PHMSA identified as self-executing and that PHMSA could incorporate into the PSR without notice of public comment or previous proposed rulemaking. Section 14 of the PIPES Act of 2016 requires operators of hazardous liquid pipeline facilities to provide safety data sheets to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center. Section 25 of the PIPES Act of 2016 requires operators of underwater hazardous liquid pipeline facilities in HCAs that are not offshore pipeline facilities and that any portion of which are located at depths greater than 150 feet below the surface of the water to complete ILI assessments appropriate to the integrity threats specific to those pipelines no less frequently than once every 12 months. Furthermore, section 25 of the PIPES Act of 2016 requires that operators use pipeline route surveys, depth of cover surveys, pressure tests, ECDAs, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, as necessary to assess the integrity of those pipelines on a schedule based on the risk that the pipeline facility poses to the HCA in which the facility is located. PHMSA is amending the PSR by codifying the statutory language of these provisions.

III. Liquid Pipeline Advisory Committee Recommendations

The Liquid Pipeline Advisory Committee (LPAC) is a statutorily mandated advisory committee that advises PHMSA on proposed safety standards, risk assessments, and safety policies for hazardous liquid pipelines. The Pipeline Advisory Committees (PAC) were established under the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. App. 1–16) and the Federal Pipeline Safety Statutes (49 U.S.C. Chap. 601). Each committee consists of 15 members, with membership divided among the Federal and State agencies, the regulated industry, and the public.[37] The PACs advise PHMSA on the technical feasibility, practicability, and cost-effectiveness of each proposed pipeline safety standard.

On February 1, 2016, the LPAC met at the Hilton Arlington in Arlington, VA, to discuss this rulemaking. During the meeting, the LPAC considered the specific regulatory proposals of the NPRM and discussed various comments to the NPRM proposed by the pipeline industry, public interest groups, and government entities. To assist the LPAC in their deliberations, PHMSA presented a description and summary of the eight major issues in the NPRM and the comments received on those issues, as well as some sample regulatory text changes to foster discussion.

During the meeting, eight votes were taken: One vote on each major topic of the NPRM. For each major topic of the rule, the LPAC came to a consensus decision that the provisions of the rulemaking would be technically feasible, reasonable, cost-effective, and practicable, provided PHMSA made certain changes. The order the topics were discussed in, the changes the committee agreed upon, and the corresponding vote counts were as follows:

Gravity lines: In the NPRM, PHMSA proposed to subject gravity lines to reporting requirements for data gathering purposes, as there are currently no regulatory requirements for these lines and little data for potential regulatory decision-making purposes. The LPAC voted 9–1 that the NPRM, with respect to gravity lines, as published in the **Federal Register**, and the draft regulatory evaluation were technically feasible, reasonable, cost-

[37] Members from the general public include two members who have education, background, or experience in environmental protection or public safety. At least one of the five members must have education, background, or experience in risk assessment and cost-benefit analysis. No public member can have a significant interest in the pipeline, petroleum, or gas industry. At least one of the public members must have no financial interests in the pipeline, petroleum, or natural gas industries. See section 12(d), ''Liquid Pipeline Advisory Committee Charter—October 2018 to October 2020,'' *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/standards-rulemaking/pipeline/4396/lpac-charter-final-102418.pdf.*

effective, and practicable, if PHMSA made the following changes: Modify (shorten) the reporting form, require no National Pipeline Mapping System (NPMS) submissions, provide reporting exceptions for lower-risk pipelines (for example, intra-plant lines), allow a 1-year implementation period for annual reporting, and allow a 6-month implementation period for accident reporting.

The LPAC agreed that PHMSA should modify the reporting forms to gather only the data necessary for PHMSA to determine whether these lines need to be regulated in the future. LPAC members representing the pipeline industry requested that PHMSA consider reporting exceptions for lower-risk pipelines, such as intra-plant gravity lines. The same members also requested that any reporting requirements for gravity lines not include NPMS submissions, asserting that incorporating that data into a mapping system would be costly compared to the amount of risk these lines pose. LPAC members representing the public did not support these recommendations. They noted that as gravity line mileage is already limited, and the reporting requirement is only being used to gather data, excepting a subset of this limited mileage from reporting requirements would be counter-productive. Further, the public members strongly suggested that NPMS submissions be included for gravity lines, as location could be an important data point PHMSA could collect.

Gathering lines: In the NPRM, PHMSA proposed to collect information on all gathering lines and subject regulated gathering lines to periodic assessment and leak detection requirements. Much of the LPAC's discussion for gathering lines mirrored the topics discussed regarding gravity lines. During the discussion, PHMSA noted that under 49 U.S.C. 60132, only transmission-pipeline operators are required to submit mapping data for use in the NPMS. As a result, the LPAC removed language concerning NPMS submissions by gathering line operators. Ultimately, the committee voted 10–0 that the NPRM regarding gathering lines, as published in the **Federal Register**, and the draft regulatory evaluation are technically feasible, reasonable, cost effective, and practicable if PHMSA made the following changes: modify (shorten) the reporting form, allow a 1-year implementation period for annual reporting, and allow a 6-month implementation period for accident reporting.

Leak detection: In the NPRM, PHMSA proposed that all hazardous liquid pipelines transporting liquid in single phase (without gas in the liquid) include a leak detection system and have it operate and maintained per specified standards. Many commenters noted that there was no implementation period for PHMSA's proposed leak detection requirements. The LPAC proposed a 5-year implementation period for leak detection systems on existing lines and a 1-year implementation period for leak detection systems on new lines. The LPAC also recommended PHMSA not apply leak detection requirements to offshore gathering lines due to various technical challenges associated with flow monitoring and leak detecting. The LPAC voted unanimously that the NPRM, regarding leak detection, as published in the **Federal Register**, and the draft regulatory evaluation are technically feasible, reasonable, cost effective, and practicable if PHMSA made the following changes: Allow a 5-year implementation period for existing pipelines, allow a 1-year implementation period for new pipelines, and exempt offshore gathering lines from the leak detection requirements.

Clarifying other requirements: In the NPRM, PHMSA proposed to revise the IM requirements to specify additional pipeline attributes for operators to analyze when evaluating the integrity of pipelines in HCAs; to require the integration of all sources of information, including spatial relationships, when determining pipeline integrity; to require operators have a written IM plan prior to a specific pipeline's operation; and to require annual HCA segment identification and verification. During the meeting, the LPAC primarily discussed whether there should be a timeframe for implementing the specific data attributes and integrating all sources of information when determining pipeline integrity. Committee members representing the public argued that, because these provisions were clarifications of existing requirements, operators should have already been performing many of these actions, and an extended implementation period would not make sense. Several members who represented the public pushed for a 1-year implementation period. LPAC members representing the industry noted that developing data integration systems to a level that PHMSA would like could be expensive and time-consuming, possibly taking several years. Further, LPAC members representing industry noted that while a lot of data integration is already occurring in operators' IM programs, it could take some operators an extended period to adjust their software to incorporate all the items in PHMSA's proposed list. LPAC members representing industry proposed PHMSA allow operators a 3-year deadline from the rule's issuance to fully implement the proposed list of attributes. Ultimately, the LPAC voted 7–3 that the NPRM, regarding the data integration requirements, as published in the **Federal Register**, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable if operators begin implementing the requirements upon the rule's issuance with a deadline of 3 years for full implementation.

Inspections following extreme weather events: In the NPRM, PHMSA proposed requiring operators to perform inspections of pipelines that may have been affected by natural disasters or extreme weather events within 72 hours after the cessation of the event to better ensure that no conditions exist that could adversely affect the safe operation of that pipeline. The LPAC voted unanimously that the NPRM, as it relates to inspections following extreme weather events, as published in the **Federal Register**, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable, if PHMSA included the term ''landslide'' as a specific extreme weather event and qualify the term ''other similar events'' as it pertains to triggering the requirements of performing an inspection by tying the term to those events ''that the operator determines to have a significant likelihood of damage to infrastructure.'' Further, the LPAC recommended PHMSA clarify that the purpose of the inspection is to ''detect conditions that could adversely affect the safe operation of the pipeline'' and not ''ensure that no conditions exist that could adversely affect the safe operation of the pipeline.'' The LPAC also recommended PHMSA clarify that the inspection per these requirements would be an initial inspection, conducted within 72 hours of the area being safely accessible by personnel and equipment, to determine if any damage has occurred and whether additional assessments are necessary.

Periodic assessments in non-HCAs: In the NPRM, PHMSA proposed to require operators to assess non-HCA pipelines at least once every 10 years using ILI or other equivalent methods. The LPAC agreed on this requirement and wanted to ensure it was not more restrictive than the requirement for assessing lines in HCAs. The LPAC voted unanimously that, regarding the provisions of the NPRM related to periodic assessments, the NPRM, as published in the **Federal Register**, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable if PHMSA ensured that the periodic assessment requirement applies to regulated pipelines that are not currently subject to the IM requirements at § 195.452, and made the methods operators use to assess non-HCA pipelines consistent with the methods operators use to assess HCA pipelines and allow operators to choose the appropriate tool for the appropriate threat.

Making all pipelines in HCAs able to accommodate ILI tools: In the NPRM, PHMSA proposed to require all pipelines in HCAs be capable of accommodating ILI tools within 20 years. The LPAC voted 9–1 that, regarding the provision of the rule requiring the use of ILI tools in all HCAs, the NPRM, as published in the **Federal Register**, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable provided PHMSA insert a phrase stating that an operator can also file a petition if it determines it would abandon or otherwise shut down a pipeline because of the compliance cost of the provision.

Repair criteria: In the NPRM, PHMSA proposed to make various changes to the existing repair criteria to reflect an improved prioritization of repairing abnormal pipeline conditions. The LPAC voted unanimously that, with regard to repair criteria for both HCA and non-HCA pipeline segments, the NPRM, as published in the **Federal Register**, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable if PHMSA considers allowing recognized engineering analyses to determine whether applicable dents and cracks are non-injurious and need no further investigation, and gives ''full and equal consideration to the industry comments that were discussed [at the meeting].'' [38] Those hazardous liquid industry comments provided at the LPAC meeting for PHMSA to consider were as follows:

Repair Criteria for both HCA and non-HCA pipeline segments:

1. Regarding ''Immediate'' conditions:

a. Include crack anomalies greater than 70 percent of wall thickness or the tool's maximum measurable depth if it is less than 70 percent;

b. Remove specific references to ''any indication'' of significant stress corrosion cracking (SCC) and selective seam weld corrosion (SSWC).

c. Allow for an industry recognized engineering analysis to determine those dents that are non-injurious and require no further investigation; and

d. Instead of addressing cracks and SSWC specifically, expand the various accepted failure models that identify an anomaly that does not have the remaining strength to exceed 1.1 times the MOP at the location of the anomaly, which should also include injurious cracks and SSWC.

2. Regarding 270-day conditions for HCAs and 18-month conditions for non-HCAs:

a. Revise the existing reference to cracks and include crack anomalies greater than 50 percent of wall thickness or the tool's maximum measurable depth if it is less than 50 percent;

b. Allow for an industry recognized engineering analysis to determine those dents that are non-injurious and require no further investigation; and

c. To address cracks and SSWC, expand the various accepted failure models that identify an anomaly that does not have the remaining strength to exceed 1.25 times the MOP at the location of the anomaly.

3. Add a ''Scheduled condition:''

a. Anomalies that do not meet the 270-day or the 18-month repair criteria but have the possibility to grow before the next segment inspection are subject to predictive modeling of remaining strength; and

b. Investigate in the years prior to the next inspection if the predicted burst pressure is less than 1.1 times the MOP at the location of the anomaly.

In this final rule, PHMSA considered the recommendations of the LPAC and adopted them as PHMSA deemed appropriate. To summarize, the major changes PHMSA has made in this rule that deviate from the LPAC recommendations are as follows: (1) PHMSA has added an additional requirement that operators notify the appropriate PHMSA Region Director when they are unable to inspect infrastructure impacted by extreme weather within 72 hours; (2) PHMSA has removed the phrase ''other similar event'' from the extreme weather inspection requirements; (3) PHMSA has changed a word in the regulatory text for non-HCA assessments, to provide that operators must assess ''line pipe'' (instead of ''pipelines defined under § 195.1'') not subject to the IM requirements at § 195.452; (4) PHMSA has restricted the non-HCA periodic assessment requirement to onshore, piggable, line pipe only, which removed the proposed assessment requirement for covered offshore lines and for regulated rural gathering lines; (5) PHMSA has removed the leak detection requirement for rural regulated gathering lines at § 195.11; and (6) PHMSA declined to move forward with the repair criteria and timelines as proposed for both HCAs and non-HCAs and has, instead, reverted to the existing non-IM repair language in § 195.401(b)(1) and the existing IM repair language at § 195.452(h). In the comments section, for each major topic of this final rule, PHMSA broadly discusses specific amendments proposed during the meeting and the corresponding discussion. PHMSA also discusses the instances where PHMSA did not adopt the specific recommendations of the LPAC.

IV. Analysis of Comments and PHMSA Response

On October 13, 2015, PHMSA published an NPRM (80 FR 61609) proposing several amendments to 49 CFR part 195. The NPRM proposed amendments addressing the following areas:

(1) Reporting requirements for gravity lines.

(2) Reporting requirements for gathering lines.

(3) Inspections of pipelines following extreme weather events.

(4) Periodic assessments of pipelines not subject to IM.

(5) Repair criteria.

(6) Expanded use of leak detection systems.

(7) Increased use of in-line inspection tools.

(8) Clarifying other requirements.

Seventy organizations and individuals submitted comments in response to the NPRM, including public representatives, private citizens, industry service providers, individual pipeline operators, and trade associations representing pipeline operators. Some of the comments PHMSA received in response to the NPRM were comments beyond the scope or authority of the proposed regulations. The absence of amendments in this proceeding involving other pipeline safety issues (including several topics listed in the ANPRM) does not mean that PHMSA determined additional rules or amendments on other issues are not needed. Such issues may be the subject of other existing

[38] At the Advisory Committee meeting, member Craig Pierson, representing the pipeline industry, submitted for the members' consideration a written recommendation regarding repair criteria anomalies.

rulemaking proceedings or future rulemaking proceedings.

The remaining comments reflect a wide variety of views on the merits of particular sections of the NPRM. The substantive comments received on the NPRM are organized by topic below and are discussed in the appropriate section with PHMSA's response and resolution to those comments.

A. Reporting Requirements for Gravity Lines

1. PHMSA's Proposal

Gravity lines, pipelines that carry product by means of gravity, are currently exempt from PHMSA regulations. Many gravity lines are short and within tank farms or other pipeline facilities; however, some gravity lines are longer and can build up large amounts of pressure because they traverse areas with significant elevation changes, which could have significant consequences in the event of a release.

For PHMSA to effectively analyze gravity line safety performance and risk, PHMSA needs basic data about those pipelines. PHMSA has the statutory authority to gather data for all pipelines (49 U.S.C. 60117(b)), and that authority was not affected by any of the provisions in the 2011 Pipeline Safety Act. Accordingly, PHMSA proposed to add § 195.1(a)(5) to require that the operators of all gravity lines comply with requirements for submitting annual, safety-related condition, and incident reports.

2. Summary of Public Comment

PHMSA received comments from trade organizations, citizen groups, and individuals on the scope and format of the reporting requirements. To reduce the reporting burden, industry representatives (API–AOPL, the GPA Midstream Association (GPA) and Energy Transfer Partners (ETP)) recommended that PHMSA create a new abbreviated annual report with input from operators to separate the reporting of pipeline data for regulated pipelines and those not currently subject to 49 CFR part 195. Specifically, API noted that pipelines not currently covered under part 195 (gravity lines) are not subject to operator qualification, control room management, leak detection, and HCA requirements, and therefore those areas should be excluded from reporting. The Texas Pipeline Association requested that reporting be limited to annual and incident reports, a suggestion also supported by the ETP. API–AOPL commented that industry experience indicates that the cost and time burdens associated with the reporting requirements for gravity lines exceeded the cost estimate cited by PHMSA in the NPRM.

The Environmental Defense Center requested that the reporting requirements include the location, operation, condition, and history of the pipelines, and multiple citizen groups requested that GIS mapping be required for pipelines. In addition to GIS mapping information, the Western Organization of Resource Councils and the Alliance for Great Lakes et al. recommended that PHMSA also require pipeline operators to meet minimum safety standards for all pipelines, a comment echoed by numerous other citizen groups and individuals. These commenters also requested that inspection reports, notices of violation, and similar documents be made readily available to the public.

Trade organizations made additional comments regarding the applicability and implementation timeline for the reporting requirements. API–AOPL and other industry representatives requested that the data collection be narrowed, such that it would apply only to those gravity lines that could present a risk to the public, which: (1) Travel outside of facility boundaries for at least 1 mile, (2) operate at a specified minimum yield strength level of twenty percent or greater, and (3) are not otherwise exempted in § 195.1(b). On this same basis, Denbury Resources added a request to exempt CO_2 pipelines. Finally, API–AOPL requested that PHMSA extend the proposed implementation period to 1 year after the effective date of the final rule.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA modify the NPRM to (1) require reporting from gravity pipeline operators using streamlined forms, (2) not require integration of gravity lines into NPMS, (3) provide exceptions for lower-risk pipelines (*e.g.,* intra-plant lines), and (4) set a 1-year implementation period for the annual reporting requirement and a 6-month implementation period for the accident reporting requirement.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and timing of the requirements for gravity lines. After considering these comments and LPAC input, PHMSA is modifying the exception for gravity lines at § 195.1 as it pertains to reporting requirements. This change will allow PHMSA to require operators of gravity lines to report information annually, starting 1 year from the rule's effective date, and to report accidents and safety-related conditions starting 6 months from the rule's effective date. PHMSA considers these deadlines practicable in view of the limited scope of the information requested for these lines.

PHMSA focused collection on those data elements that will enable the agency to assess the risk posed by these lines and determine whether requirements that are more stringent are warranted in the future. To facilitate reporting and address commenters' concerns about providing clear instructions on data elements that operators must fill out for gravity lines, PHMSA has modified its existing reporting form to provide clear instructions, including skip patterns, for relevant sections. In response to API's specific suggestions regarding operator qualification, control room management, leak detection, and HCA reporting, these revisions exempted gravity lines from any fields that involve ''Could Affect HCA'' data. This targeting of the information collection request will reduce the burden associated with providing the information, as was requested by commenters. PHMSA recognizes that operators who are not currently submitting data will have to register with PHMSA to obtain an Operator Identification Number (OPID) under § 195.64, but the associated burden is minimal; PHMSA estimates that fewer than 10 operators would need to submit information for gravity lines. PHMSA estimates the total reporting burden at 66 hours per year, on average.

During the LPAC meeting, the committee reached consensus on requiring gravity line operators to report safety-related conditions. These conditions could lead to significant consequences and are important data points for PHMSA to determine whether additional gravity line regulations may be necessary in the future.

As explained previously, the purpose of the information collection is to support evaluation of the risk posed by gravity lines on the public. With this goal in mind, PHMSA is receptive to commenters who noted that pipelines located within the confines of a facility or in close proximity (within 1 mile) to a facility and do not cross a waterway currently used for commercial navigation pose a lower risk to the public and the environment. PHMSA has decided to exempt these lines from the reporting requirements. The language for this exception is similar to the language of an existing exception for low-stress pipelines at § 195.1.

Further safety-related condition reporting exceptions at § 195.55(b) will help minimize the reporting burdens for operators. In the NPRM, PHMSA did not intend to propose requiring mapping of gravity lines at this time and therefore is finalizing the rule without this requirement. PHMSA understands commenters' concerns that gravity line NPMS data submissions could be costly and burdensome. However, as PHMSA is not requiring these submissions as a part of this final rule's reporting requirements, the cost and burden of these submissions were not and should not be considered as a part of the cost-benefit analysis. If PHMSA determines, following analysis of the data received on gravity lines, that mapping of these lines or expanding reporting applicability to lines exempted in this final rule would be beneficial to improve public safety or protect the environment, it may consider additional requirements in a future rulemaking.

Similarly, PHMSA is not requiring telephonic reporting of accidents involving gravity lines at this time but may reassess this requirement in a future rulemaking if analyses of the data suggest that doing so would enhance prevention, preparedness, and response to hazardous liquid releases from gravity lines.

Comments relating to public reporting and the reporting of specific pipeline attributes discussed issues that PHMSA did not propose in the NPRM and are therefore out-of-scope and could not be considered for this rulemaking. Similarly, comments discussing minimum safety standards be applied to gravity lines were also out-of-scope because they requested more stringent requirements than what PHMSA proposed in the NPRM.

B. Reporting Requirements for Gathering Lines

1. PHMSA's Proposal

In the NPRM, PHMSA also proposed to extend the reporting requirements of 49 CFR part 195 to all hazardous liquid gathering lines. Recent data indicates that PHMSA regulates less than 4,000 miles of the approximately 30,000 to 40,000 miles of onshore hazardous liquid gathering lines in the United States.[39] That means that about 90 percent of the onshore gathering line mileage is not currently subject to any minimum Federal pipeline safety standards. Congress also ordered the review of existing State and Federal regulations for hazardous liquid gathering lines in the Pipeline Safety Act of 2011, to prepare a report on whether any of the existing exceptions for these lines should be modified or repealed, and to determine whether hazardous liquid gathering lines located offshore or in the inlets of the Gulf of Mexico should be subjected to the same safety standards as all other hazardous liquid gathering lines. Based on the study titled ''Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines'' [40] that was performed by the Oak Ridge National Laboratory and published on May 8, 2015, PHMSA proposed additional regulations to help ensure the safety of hazardous liquid gathering lines.

For PHMSA to effectively analyze safety performance and risk of gathering lines, we need basic data about those pipelines. PHMSA has statutory authority to gather data for all gathering lines (49 U.S.C. 60117(b)). Accordingly, PHMSA proposed to add § 195.1(a)(5) to require that the operators of all gathering lines (whether onshore, offshore, regulated, or unregulated) comply with requirements for submitting annual, safety-related condition, and incident reports.

2. Summary of Public Comment

PHMSA received comments on hazardous liquid gathering lines that echoed those for gravity lines. Citizen groups and individuals again requested that the requirements for these lines include GIS mapping and minimum safety standards; that the reporting include location, operation, condition, and history; and that inspection reports, notices of violation, and similar documents be made available to the public. Trade organizations again commented on compliance costs and recommended that the reporting requirement be limited to annual and incident reports with an abbreviated form, have a phase-in implementation over 1 year, and exempt lower-risk pipelines. Specifically, API noted again that, as rural gathering lines are not subject to operator qualification, control room management, leak detection, and HCA requirements, those areas should be excluded from reporting.

Trade organizations also made several additional recommendations related to the scope of applicability, the scope of requirements, and implementation. The Independent Petroleum Association of America (IPAA) commented that PHMSA exceeds its authority in requiring operators of gathering lines to submit annual, safety-related condition, and incident reports. The GPA and other organizations noted that PHMSA did not fully account for the burden increase and cost of the reporting requirements for gathering lines in the preliminary RIA. The GPA recommended that information requested under § 195.61 and § 195.64 be excluded from data collection. Numerous trade organizations identified accident reporting for these lines as costly and duplicative. The Louisiana Mid-Continent Oil and Gas Association (LMOGA) commented that most, if not all accident information requested for gathering lines is already required to be reported under other existing Federal and State regulations, and the GPA recommended that information collected through an abbreviated Annual Report could be paired with Accident Reporting on Form F 7000–1 (rev 7–2014). LMOGA also recommended that mapping of gathering lines not be required because of incidental environmental impacts on wetlands, permitting, and resource costs for teams to enter wetlands and track these lines.

The Offshore Operators Committee (OOC) requested that PHMSA make clear in the final rule that the agency's intent is not to have the proposed reporting requirements apply to gathering lines offshore within State waters that are currently not regulated by PHMSA or the Bureau of Safety and Environmental Enforcement (BSEE) or to other gathering lines that are regulated by BSEE.

Finally, commenters asked for implementation periods that ranged from 1 year (API–AOPL) to 10 years (Enterprise Products Partners) after the effective date of the rule.

During the meeting on February 1, 2016, the LPAC recommended that PHMSA modify the NPRM to (1) require reporting from gathering pipeline operators using streamlined forms and (2) set a 1-year implementation period for the annual reporting requirement and a 6-month implementation period for the accident reporting requirement.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and timing of the requirements for gathering lines. Regarding the comment that the proposed reporting requirement of § 195.1(a)(5) exceeds PHMSA's statutory authority, PHMSA notes that the Federal Pipeline Safety Statutes state, in relevant part, ''[t]he Secretary may require owners and operators of gathering lines to provide the Secretary

[39] GAO–12–388: ''Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety,'' March 2012, pg. 7; *http://www.gao.gov/assets/590/589514.pdf*.

[40] *http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/report_to_congress_on_gathering_lines.pdf*.

information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines.'' 49 U.S.C. 60117(b). PHMSA has determined that, in order to decide whether and to what extent to regulate gathering lines, as permitted by Congress, PHMSA requires pertinent information about those pipelines, including elements of the data contained in annual, safety-related condition, and incident reports. With this reporting requirement, PHMSA is not encroaching on the States' regulatory authority, nor creating new jurisdiction. Rather, PHMSA is collecting pertinent information to determine if future regulation is necessary for the statutory purpose of promoting pipeline safety.

More specifically, PHMSA is collecting items in the annual report that primarily include the mileage count for those gathering lines currently unregulated, the diameters of those lines, and whether they are operating at greater or less than 20 percent SMYS. The goal of collecting this specific information is to provide PHMSA with a better understanding of the scope of the Nation's gathering pipeline infrastructure. As previously stated, recent data indicates PHMSA regulates only approximately 4,000 miles of the estimated 30,000 to 40,000 miles of onshore hazardous liquid gathering lines in the United States. That means that as much as 90 percent of the onshore gathering line mileage is not currently subject to any minimum Federal pipeline safety standards, and little is known about that mileage.

In requiring accident reports for otherwise unregulated gathering lines, PHMSA is collecting data that includes the underlying cause for the accident, where the accident was located and how it was reported to the operator, and a value for any property damage caused. This data will be essential to understanding and managing risk. PHMSA uses information reported by pipeline operators to identify trends, provide performance measures, and understand the causes and consequences of pipeline incidents. Reporting requirements are in place for all pipelines except for the gravity and gathering pipelines addressed by this final rule. Each year, the U.S. Coast Guard's National Response Center receives several notifications of hazardous liquid releases involving ''gathering lines,'' but details on these releases are not sufficient to understand the factors that contributed to the releases and the damages, or to evaluate whether the lines involved are gathering lines over which PHMSA has jurisdiction.[41] The reporting requirements for gathering lines will help PHMSA have a more complete understanding of the risks these lines may pose.

PHMSA notes that one of its challenges is to understand and target risk, which requires a systematic approach to risk management, including a ''comprehensive understanding of the factors contributing to risk and the ability to focus resources in those areas that pose the greatest risk.'' One of PHMSA's strategies for dealing with this challenge is to improve data collection and analysis, collect the right data to evaluate risks from unregulated entities, and improve the transparency of information and public awareness of pipeline and hazardous materials safety issues. The long-term benefits of having better information may include reducing incidents, enhancing incident response, and increasing public confidence.

As such, PHMSA is finalizing the requirement for operators of gathering lines to report information annually, starting 1 year from the rule's effective date, and to report accidents and safety-related conditions starting 6 months from the final rule's effective date. PHMSA considers these deadlines practicable in view of the scope of the information requested. To facilitate reporting and address commenters' concerns about providing clear instructions on data elements that must be filled out for gathering lines, PHMSA has modified its existing reporting form to provide clear instructions, including skip patterns, on the relevant sections that gathering line operators must fill out. In response to API's specific suggestions regarding operator qualification, control room management, leak detection, and HCA reporting, these revisions exempted rural gathering lines from any fields that involve ''Could Affect HCA'' data. PHMSA recognizes that operators who are not currently submitting data will have to register for an identifier, but PHMSA expects the burden on operators to do this is small. In its analysis, PHMSA assumed that a majority of the reporting of currently unregulated gathering lines would be done by operators who already have OPIDs. PHMSA estimates that, at a minimum, approximately 20 operators will need to submit information for gathering lines for the first time, and another 56 operators will add information about gathering lines to their existing annual reports. PHMSA estimates the total reporting burden at 402 hours per year, on average. See the revised RIA accompanying the final rule for additional detail.

Some commenters requested that PHMSA clarify whether these reporting requirements applied to offshore gathering lines in State waters. As the purpose of the information collection is to evaluate the public risk posed by gathering lines, PHMSA found it appropriate to extend the reporting requirements to certain offshore gathering lines in State waters.

In its proposal, PHMSA did not intend to require mapping or NPMS submissions for gathering lines. Under 49 U.S.C. 60132, only transmission line operators are required to submit mapping data for use in the NPMS; PHMSA does not have the explicit authority to collect NPMS data for gathering lines. PHMSA is therefore finalizing the rule without imposing this requirement on operators of gathering lines.

Similar to requirements for gravity lines, PHMSA is not requiring telephonic reporting of accidents involving gathering lines to PHMSA at this time since such a requirement would not support the purpose of this data collection effort, which is to enable PHMSA to evaluate risk over time for potential future action. PHMSA notes that operators must still report spills to the National Response Center and other relevant authorities. PHMSA will reassess the utility of requiring notification for incidents involving gathering lines in a future rulemaking if the analyses suggest that such notifications would enhance prevention, preparedness, and response to hazardous liquid releases from gathering lines.

Certain commenters also stated their belief that PHMSA neglected to account for the costs and burden associated with the initial compiling of the data needed to complete the forms. In many cases, the commenters suggested, information may not have been recorded or may not have been provided during mergers or acquisitions. PHMSA noted in the RIA that it expects operators to have the requested information readily available, as it is essential for pipeline operation and safety. PHMSA allows operators to enter ''unknown'' when values cannot be determined for certain data fields. In the burden estimate, PHMSA allotted time for operators to compile the proper data and organize it into the requested format. See the RIA for further details. PHMSA did not impose minimum safety standards on currently unregulated gathering lines, as some

[41] NRC data for 2010 through 2014 show 116 incidents categorized as ''pipeline'' incidents and that specifically include the term ''gathering'' in the incident description. Many more pipeline incidents could also be from gathering lines.

commenters suggested, because the agency currently does not have data to analyze what risk, if any, those lines may pose to surrounding communities and environments. However, under these provisions, PHMSA will gather data on unregulated gathering lines and will use that data to determine whether additional safety regulations may be necessary.

C. Pipelines Affected by Extreme Weather and Natural Disasters

1. PHMSA's Proposal

Recent events demonstrate the importance of ensuring that our Nation's waterways are adequately protected in the event of a natural disaster or extreme weather. PHMSA is aware that responsible operators might do such inspections; however, because it is not a requirement, some operators do not. Therefore, PHMSA proposed to require that operators perform an additional inspection within 72 hours after the cessation of an extreme weather event such as a hurricane or flood, an earthquake, a natural disaster, or other similar event.

Specifically, PHMSA proposed that an operator must inspect all potentially affected pipeline facilities after an extreme weather event to help ensure that no conditions exist that could adversely affect the safe operation of that pipeline. The operator would be required to consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the inspection required. The initial inspection must occur within 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by available personnel and equipment required to perform the inspection. Based on PHMSA's experience and coordination with operators following natural disasters, PHMSA has found that 72 hours is reasonable and achievable in most cases. If an operator finds an adverse condition, the operator must take appropriate remedial action to best ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection. PHMSA specifically asked for comments on how operators currently respond to these events, what type of events are encountered, and if a 72-hour response time is reasonable.

2. Summary of Public Comment

Some trade organizations recommended that certain requirements be eliminated altogether or consolidated to reduce what they considered to be duplicative of existing emergency planning requirements in § 195.402(e)(4).

Commenters were nearly unanimous in requesting that PHMSA clarify the definition of extreme weather event, the 72-hour timeline, and the timeline for mitigating or repairing anomalies. The GPA recommended that PHMSA either define exactly which events require response and inspection or establish performance expectations without partially defining the criteria, while the County of Santa Barbara recommended that the proposed regulations specify a threshold at which action would be required. Congresswoman Lois Capps (California) recommended that PHMSA include definitions and/or citations of existing definitions for qualifying events and the responsible party for such a determination. Congresswoman Capps also recommended that PHMSA clarify the terminology for an ''appropriate method for performing the inspection'' after the event.

In addition to clarification of the definition of extreme weather event, trade groups also requested clarification of the 72-hour timeline following an extreme weather event, including how they would determine the cessation of the event, what appropriate action they would need to take following an event, and how to address the possibility of continued danger facing personnel or issues with availability of personnel and resources following an event.

API–AOPL recommended that PHMSA define cessation as the point in time when no further threats to personnel safety or equipment exist in the affected area, allowing for safe access by pipeline personnel and equipment. They also recommended that the 72-hour window commence only once personnel and equipment could safely access the affected area.

Citizen groups and individuals requested that operators be required to proactively address known risks and vulnerabilities in advance of an extreme weather event. For example, one organization recommended additional requirements to identify areas that are particularly vulnerable to extreme weather events or natural disasters, (*e.g.,* stream crossings, and to develop proactive preventive measures.) The Alaska Wilderness League et al. recommended mandatory prevention measures that include shutting down pipeline operations in case of an imminent flood to prevent spills such as the 2011 Exxon Mobil Yellowstone River spill. Citizen groups also requested immediate reporting to PHMSA when remedial action is required and that this information be made publicly available. The Environmental Defense Center requested that PHMSA provide specific, enforceable requirements for shutdown or other remedial action should an inspection reveal damage or anomalies, and that PHMSA clarify the type of events covered and the inspection methodology required.

Finally, the OOC recommended that PHMSA coordinate with BSEE and the U.S. Coast Guard for activities that occur after hurricanes.

During the meeting on February 1, 2016, the LPAC recommended that PHMSA modify the NPRM to (1) include landslides as an extreme weather event, (2) clarify that other similar events are those likely to damage infrastructure, and (3) require operators to inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of the pipeline. The LPAC also recommended that PHMSA modify the language regarding the inspection method to require operators to consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine damage and the need for additional assessments. Finally, the LPAC recommended that PHMSA clarify that the inspection must commence within 72 hours after the cessation of the event, which is defined as the point in time when the affected area can be safely accessed by the personnel and equipment, accounting for personnel and equipment availability.

3. PHMSA Response

PHMSA disagrees with the comments stating the provisions at § 195.414 are unnecessary and duplicate operation and maintenance (O&M) manual requirements already contained in the response plan requirements under § 195.402. While § 195.402 does require that operators include certain ongoing monitoring measures in their O&M manuals, the proposed § 195.414 is much more specific in requiring that operators take appropriate remedial action to best ensure the safe operation of a pipeline based on the information obtained as a result of performing the post-event inspection required under paragraph (a) of this section. This will ensure that operators take the prescribed actions; having measures described in an operator's O&M manual, as previously required, is not equivalent to action. PHMSA maintains that separate and more specific requirements are warranted to best ensure public safety and environmental protection following extreme events. Additionally, PHMSA notes that reporting is coordinated with BSEE, the U.S. Coast Guard, and other agencies under existing notification procedures if the assessment determines there was a release involving their areas of responsibility. Both 49 CFR parts 194 and 195 require operators to report spills to the National Response Center.

PHMSA appreciates the feedback provided by the commenters regarding the need for greater clarity in the definition of extreme events and natural disasters and expectations on the timing and scope of post-event inspections. In developing the requirements, PHMSA sought to balance being explicit regarding the types of events that could increase the risk of a release and therefore require inspections, with providing sufficient flexibility to account for diverse geographical and pipeline design factors. PHMSA recognizes that the language recommended by the LPAC is useful in striking this balance and adopted most its revisions in the final rule under §§ 195.414(a), (b), and (c). PHMSA is removing the language ''other similar event'' as PHMSA found the phrase to be vague and unnecessary to accomplish the goals of the provision but is maintaining the LPAC's recommended language regarding the ''likelihood to damage infrastructure.'' Per the finalized requirement, operators must inspect all potentially affected pipeline facilities following extreme weather events or natural disasters with the likelihood of damaging infrastructure, such as named hurricanes or tropical storms; floods that exceed the high-water banks of rivers, shorelines or creeks; and landslides or earthquakes occurring within the area of a pipeline, in order to detect conditions that could adversely affect the safe operation of that pipeline. As discussed earlier in this document, the conditions that trigger this requirement are those that have the potential to cause river scour, soil subsidence, or earth movement, all of which can subject a pipeline to additional external loads and forces and cause the pipeline to fail. Pipeline operators are already required to understand and analyze the impact such weather events and natural disasters may have on their systems based the physical characteristics, operating conditions, location, and prior history of susceptible pipelines.

PHMSA retained the remedial actions unchanged from the proposal. While PHMSA intends for operators to inspect pipelines as soon as possible after an event ends, PHMSA also agrees with commenters that personnel safety is paramount. Accordingly, PHMSA clarified that the cessation of the event occurs as soon as it is safe for personnel and equipment to access the area. Operators are responsible for determining when each site is safe enough for entry.

In response to commenters who sought greater flexibility in the timing of the inspections by leaving it up to the operators, PHMSA disagrees and maintains that setting clear and consistent timelines is essential to ensuring that all operators detect and address any issues promptly. The final rule does provide a fallback to operators who must delay the start of actions beyond this time due to availability of equipment, but these operators must notify the Regional Director. This addition to the LPAC-approved language allows operators to retain flexibility due to unavailable equipment, while ensuring accountability and prompt action. PHMSA considers 72 hours to be a reasonable period for mobilizing personnel and equipment following an event.

In response to commenters who expressed concerns that inspections cannot be reasonably be completed within the 72-hour window, PHMSA notes that the proposal did not require completion of the inspections within 72 hours, and neither does the final rule; PHMSA recognizes that this needed to be clarified in the rule text and has done so in the final rule. The final rule accordingly describes the actions it expects operators to perform, starting within 72 hours after the cessation of the event. Recognizing that some actions will need to be site-specific, PHMSA provides flexibility to operators to determine the measures that are appropriate to the event, pipeline design, and circumstances.

PHMSA is receptive to the recommendation that operators should take precautionary measures to minimize exposure in advance of and during an extreme event (*e.g.,* reducing operating pressure or shutting down a pipeline), and notes that the current IM regulations require operators to know and understand risks to their system, which includes the threat of extreme events such as flooding or wind damage. To execute their IM programs and assessments on non-HCA lines as per this final rule, operators will need to have pipeline system information to address risks to their systems. Operators will use the information they have gathered on their entire pipeline system to monitor conditions and determine any anticipated risks to their pipelines, including extreme weather events. Given that the existing IM regulations require preventive and mitigative measures for HCAs, which often include river crossings, it is appropriate for this section to address post-natural disaster inspections for damage specifically.

D. Periodic Assessment of Pipelines Not Subject to IM

1. PHMSA's Proposal

PHMSA proposed to require integrity assessments for pipeline segments in non-HCAs. PHMSA believes that expanded assessment of non-HCA pipeline segments areas will provide operators with valuable information they may not have collected if regulations were not in place; such a requirement would help ensure prompt detection and remediation of corrosion and other deformation anomalies in all locations, not just HCAs. Specifically, the proposed § 195.416 would require operators to assess non-HCA (non-IM) pipeline segments with an ILI tool at least once every 10 years, which allows operators to prioritize HCA assessments. PHMSA proposed to allow other assessment methods if an operator provides OPS with prior written notice that a pipeline is not capable of accommodating an ILI tool. Such alternative technologies would include hydrostatic pressure testing or appropriate forms of direct assessment.

Although imposing the full set of IM requirements in § 195.452 on non-HCA pipeline segments was not proposed, operators would be required to comply with the other provisions in 49 CFR part 195 in implementing the requirements in § 195.416. That includes having appropriate provisions for performing periodic assessments and any resulting repairs in an operator's procedural manual (see § 195.402); adhering to the recordkeeping provisions for inspections, tests, and repairs (see § 195.404); and taking appropriate remedial action under proposed § 195.422, which, based on the existing IM repair criteria at § 195.452(h), identified specific types of anomalies and the timeframes by which they must be remediated. Operators would also follow the requirements for ''discovery of condition,'' where the discovery of a condition occurs when an operator has adequate information to determine that a condition exists. The operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to determine whether the condition could adversely affect the safe operation of the pipeline, unless 180 days is impracticable as determined by

PHMSA. PHMSA sought public comment on the alternatives it considered under this specific proposal and on quantifying these alternatives in the regulatory impact analysis.

2. Summary of Public Comment

Trade organizations offered comments and language revisions on the methods and requirements included in the periodic assessments, implementation period, inspection intervals, and exemptions for lower risk pipelines. Enterprise Products Partners requested that operators be afforded the latitude they have under current IM regulations to determine the actual threats to pipeline integrity present on a given segment and to tailor their integrity assessment program accordingly. For instance, Enterprise suggested that PHMSA revise the proposal to clarify that a crack tool is not required for every ILI assessment, stating specifically that ''an additional ILI crack tool is beneficial only when there is an identified threat to the pipeline segment that could result in cracks, such as cyclic fatigue. Yet PHMSA proposes to require a [crack tool] in all circumstances and on every pipeline segment.'' Other trade organizations echoed this and requested that PHMSA incorporate alternatives to ILI tools for periodic assessments into the rule. Trade organizations also recommended that PHMSA ensure the rule is consistent with existing IM rules, including the reassessment intervals and implementation period. The Texas Pipeline Association requested that reassessment intervals be based on sound engineering judgement and industry consensus standards. Finally, trade organizations recommend that PHMSA limit and specify the type of pipelines to which the requirement would apply, with some commenters requesting specific exemptions for short lines and CO_2 pipelines. API–AOPL requested that PHMSA clarify that operators would not need to run assessments on idle or out-of-service pipelines. API–AOPL also requested that PHMSA clarify that it intends for the requirements to include transmission lines only. Finally, the GPA requested that PHMSA rely on American Society of Nondestructive Testing (ASNT) ILI PQ as the standard for data analysis rather than the current language ''qualified by knowledge, training, and experience.'' The GPA submitted additional comments to PHMSA on March 24, 2016, expressing concerns that PHMSA misrepresented aspects of this proposal during the LPAC meeting. In the LPAC meeting the GPA claimed that PHMSA asserted that currently regulated gathering lines are subject to assessments; the GPA believes that this statement was inaccurate and led to a vote by the committee that was not based on accurate facts. Further, the GPA suggested that ''it is possible there are gathering lines in non-rural areas which do not meet the Census Bureau definitions for high or other population areas. Thus, when properly applying the regulations as currently written, there are gathering lines, which are regulated by PHMSA and its state partners for safety purposes that are not subject to periodic assessments.''

Trade organizations also commented on the cost of expanding requirements for pipelines located outside of HCAs. The Texas Pipeline Association commented that raising the level of regulation on facilities outside of HCAs will redirect resources from high-risk areas to lower-risk areas. They requested that PHMSA consider the costs to operators of the proposed changes related to facilities outside of HCAs. The OOC also commented that offshore lines present unique challenges that make them ill-fitted for ILI technology and hydrotests.

Other groups and individuals commented on the methods and requirements included in the periodic assessments, inspection intervals, and additional requirements. A 5-year inspection interval was generally favored by citizen groups and individuals, including the Alliance for Great Lakes Et al. Congresswoman Capps highlighted that a 3-year interval between inspections had proven to be inadequate to detect corrosion that caused the Plains All American oil pipeline rupture in May 2015. These commenters also requested clarification that alternative methods of assessment must account for inspection along the entire pipeline both inside and outside HCAs and expressed concern with waivers for ILI tools or the use of direct assessment.

The NTSB requested that PHMSA harmonize the gas and liquid regulations to the maximum extent practicable and cautioned that direct assessment is an ineffective alternative technology for IM when applying the 10-year assessment requirement for the integrity of an entire pipeline. They recommended that the IM program encompass a broad range of available IM technologies including, but not limited to, ILI, magnetic flux leakage, ultrasonic testing, and tests directed at determining the integrity of the pipe coating.

Finally, some citizen groups and individuals requested that inspection reports be made publicly available and that operators be required to submit primary inspection results and data to PHMSA. The Environmental Defense Center recommended third-party verification of inspection reports based on corrosion underreporting. These groups also requested risk assessment on non-IM pipelines and annual inspections for all federally regulated hazardous liquid pipelines.

During the February 1, 2016, meeting, the LPAC recommended PHMSA modify the NPRM to clarify its application to pipelines regulated under § 195.1 that are not subject to the IM requirements in § 195.452. The LPAC also made additional language recommendations to clarify the method of the assessment when ILI tools are impracticable, including pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters. PHMSA notes that the LPAC, with minor tweaks, found the provision for requiring operators to perform these periodic assessments on all covered pipelines not subject to the integrity management requirements under § 195.452 to be a cost-effective, practicable, and technically feasible provision.

However, several commenters noted challenges and cost-benefit concerns with assessing offshore lines and regulated rural gathering lines as a part of this proposal. In this final rule, PHMSA is limiting the assessment requirement to onshore, non-HCA, non-gathering lines that can accommodate inline inspection tools.

Under the current regulations, PHMSA notes that approximately 45 percent of hazardous liquid pipelines are required to be assessed per the IM requirements by being located within an HCA or because they can affect an HCA. PHMSA has determined that, through this provision, most onshore non-HCA mileage will be assessed at a consistent rate. Further, as pipeline operators continue to replace pipe through modernization projects and repairs, PHMSA assumes that virtually all the Nation's pipeline mileage will be piggable within the next few decades.

In the NPRM, PHMSA did not intend for the requirements applicable to lines outside of HCAs to be more stringent than those applicable to lines in HCAs. PHMSA agreed with the commenters and the LPAC that it is appropriate to provide the same flexibility for the assessment of lines outside of HCAs as lines within HCAs, but PHMSA notes that many of these concerns appeared to be in response to PHMSA's requirement to assess all non-HCA lines, even ones that were not readily piggable. As discussed above, this final rule's non-HCA assessment requirement now applies to piggable, onshore transmission line only. This final rule does allow operators to use pressure testing, direct assessment, or other technology in cases when in-line inspections are impracticable. PHMSA has determined that ILI tools may not be available for all pipe diameters and threats being assessed, and providing operators the ability to use these other assessment methods on piggable lines is appropriate at this time.

Further, per the comments received from commenters, including API and Enterprise, related to the use of crack tools, PHMSA has revised the final rule, at both §§ 195.416 and 195.452, to require crack tools only when there is an identified or probable risk or threat supporting their use. For example, if operators have identified a pipeline segment with identified or probable risks or threats related to corrosion and deformation anomalies, including dents, gouges, or grooves, then the operator must assess that segment with a tool capable of detecting those anomalies. Similarly, operators should assess pipeline segments with an identified or probable risk or threat related to cracks using a tool capable of detecting crack anomalies. Essentially, operators should always be selecting an appropriate assessment tool based on the pertinent threats to a given pipeline segment that have been identified by an operator's risk assessment. An operator's risk assessment should always be driving its integrity assessments and the integrity management program. An operator cannot properly maintain its pipeline if it does not know what threats to which the pipeline is susceptible to and which tools the company should be selecting to assess those threats. These threats can include, but are not limited to, pipe that may have manufacturing defects or have otherwise experienced in-service incidents.

Under the existing requirements of § 195.452(c)(1) (after which PHMSA modeled the new assessment requirements in § 195.416), operators must select an assessment method capable of assessing seam integrity and of detecting corrosion and deformation anomalies if the applicable pipe is low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure. PHMSA has interpreted and intended the phrase ''susceptible to seam failure'' to apply to both low-frequency ERW pipe and lap-welded pipe. In this final rule, PHMSA has expanded the assessment provisions to require operators to use a tool or tools capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies on low-frequency ERW pipe, pipe with a seam factor less than 1.0 (as defined in § 195.106(e)) [42]), or lap-welded pipe susceptible to longitudinal seam failure. Certain stakeholders may interpret this requirement to mean that these tools will need to be run on every segment of low-frequency ERW pipe, pipe with a seam factor of less than 1.0, or lap-welded pipe. However, PHMSA only explicitly requires the use of these tools for segments of low-frequency ERW pipe, pipe with a seam factor less than 1.0, or lap-welded pipe when these types of pipe are determined by an operator to be susceptible to longitudinal seam failure based on excavation findings, examinations, leaks, failures, pressure tests, inline inspections, other operating history, and the manufacturing history of the pipe vintage and its history of seam leaks and failures.

Similarly, PHMSA found that the proposed requirements for ''discovery of condition'' under § 195.416 were more stringent than the revisions proposed for § 195.452. To be consistent with the revised requirements under § 195.452 regarding the discovery of condition, the operator has 180 days to obtain sufficient information on conditions and make the required determinations, unless the operator can demonstrate that the 180-day timeframe is impracticable. In cases where an operator does not have adequate information within 180 days following an assessment, pipeline operators must notify PHMSA and provide an expected date when that information will become available. These revisions will provide consistency for the discovery of condition across all regulated HCA and non-HCA lines.

PHMSA also agreed with the commenters and the LPAC that it is necessary to clarify which pipelines fall under the non-HCA assessment requirements. However, upon further review, PHMSA found that adopting the LPAC-recommended language for § 195.416(a), by clarifying application of this requirement to pipelines regulated under § 195.1 that are not subject to the IM requirements in § 195.452, would extend this requirement beyond PHMSA's or the LPAC's intent and would cover facilities not previously intended, such as pump stations. Therefore, instead of strictly adopting the language proposed by the LPAC, PHMSA is instead specifying that these requirements apply to onshore, piggable line pipe not covered under the IM requirements, including the relevant line pipe within pump stations, but not other appurtenances and components like metering stations, tanks, etc. Further, PHMSA is not requiring IM 5-year assessments but is requiring operators to continue the implementation of the preventive and mitigative measures under IM (§ 195.452(i)) for appurtenances, pumps, tanks, etc., for these facilities that could affect a HCA. PHMSA believes this clarification captures the intent of the LPAC members.

In response to the GPA's suggestion for an alternative standard for data analysis, PHMSA's existing process for data analysis has been through a rigorous rulemaking process. PHMSA is not incorporating alternative standards into this rule making that were not included at an earlier rulemaking stage and were not subject to public comment.

Regarding the GPA's other concern as to whether PHMSA provided the LPAC with inaccurate information concerning the extent to which operators are already required to perform assessments on gathering lines versus the new assessment requirements PHMSA was proposing in the NPRM, PHMSA notes that on pages 180 and 181 of the LPAC meeting transcript PHMSA clearly states that it is proposing subjecting currently regulated rural gathering lines to periodic assessment and repair requirements in §§ 195.416 and 195.422, saying, ''When it comes to the gathering lines that we don't currently regulate, [that] the regulations don't currently address, the only requirements we're applying will be the reporting requirements that we discussed prior. In the [NPRM], when it came to regulated rural gathering lines, we proposed to subject them to the assessment requirements in [§ 195.]416 and [§ 195.]422. There's actually a proposal in the NPRM to link the two sections together, but it would not require that lines that are currently, today, not regulated to be assessed.'' The statement by PHMSA at the LPAC meeting that the GPA questions states that regulated rural gathering lines have an assessment requirement in the NPRM as opposed to currently unregulated gathering lines, which do not. Further discussion and voting at the LPAC meeting indicated that the committee members fully

[42] 49 CFR 195.106(e) has seam factors for pipe seams that need to be de-rated for maximum operating pressure determination. A de-rated seam factor would be below 1.0 and include furnace lap welded and furnace butt welded pipe seams.

understood PHMSA's proposal, with committee members clarifying the definition by asking it to be revised to ''transmission and regulated gathering lines'' and noting ''there's clarity with this [definition] now.''

Regarding the GPA's other comment on the possibility of the existence of gathering lines in non-rural areas that are not assessed, PHMSA notes this is incorrect. Currently, the only regulated gathering lines that are not subject to assessment requirements are regulated rural gathering lines, which, per their name, are in rural areas. Under existing § 195.1(a)(4), any onshore gathering lines located in non-rural areas and gathering lines located in Gulf of Mexico inlets are covered by 49 CFR part 195, and if these gathering lines are within HCAs or could affect HCAs, they are subject to the full IM program requirements, including integrity assessments, under the current § 195.452. As defined in § 195.2, a ''rural area'' means ''outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development.'' To exist outside of a ''rural area'' as that term is defined under § 195.2 (*i.e.,* a ''non-rural'' pipeline), a pipeline would have to be inside (rather than outside) the limits of any incorporated or unincorporated city, town, etc. Per the definition of an HCA at § 195.450, a pipeline in such an area would be in an HCA, and therefore would be regulated and subject to assessment requirements. Therefore, with the exception of regulated rural gathering lines, operators should be assessing all other regulated gathering lines per their IM programs.

PHMSA does not agree with API–AOPL that clarification is needed in the rule on the issue of ''idle'' pipelines. The Federal PSR list only two statuses for a pipeline: (1) In-service/active; or (2) ''abandoned,'' which the PSR defines as ''permanently removed from service.'' Although operators frequently refer to a pipeline that is not being actively used as ''idle,'' PHMSA has no current operational designation for an ''idle'' line. Unless they are abandoned in accordance with applicable procedures, pipelines that are not currently in use must meet all the requirements of the Federal PSR, including compliance with IM regulations if those pipelines are in HCAs. On March 17, 2014, a pipeline leaked crude oil into a highly populated suburb of Los Angeles, CA (Wilmington, CA), releasing an estimated 1,200 gallons of oil.[43] The pipeline was never purged and filled with inert material as per the operator's procedures required by the regulations, and the operator (who bought the pipeline from another operator), believed the pipeline was ''abandoned.'' This demonstrates the fact that pipelines that have been ''idled'' can still present a safety risk and must be treated as active pipelines. Further, as operators can restart ''idle'' lines and transport product later, it is important that operators maintain these lines to the same level of safety and standards as an active, in-service line. Accordingly, PHMSA expects operators of ''idle'' lines to perform assessments and adhere to all the applicable regulations based on the line's location.

PHMSA considered the requests it received to make inspection reports for non-HCA lines publicly available and to require third-party inspection report verification. PHMSA determined that promulgating those requirements would make assessing non-HCA lines more burdensome than assessing HCA lines.

Regarding requests that PHMSA require non-HCA inspections at 5-year intervals to ensure a larger number of populations and properties are protected, PHMSA notes that setting the non-HCA assessment interval to 5 years would make it equal to that for lines in HCAs. Lowering the non-HCA assessment period to any time below 5 years would make it more stringent than the requirement for HCAs and would not allow operators to prioritize those higher-consequence areas first. Similarly, requiring a yearly inspection of all hazardous liquid pipelines, as some commenters suggested, would be overly burdensome and would work against risk-based prioritization.

Many commenters also requested that PHMSA require operators to perform risk assessments on non-IM pipelines. As discussed in the previous section on extreme weather events, PHMSA expects operators will need to have a certain amount of information on their HCA and non-HCA pipelines, including the environment in which they operate, for them to properly assess risk and the current condition of their pipeline system and to select the proper tool(s) for an adequate threat analysis. Operators cannot properly perform assessments if they do not know or understand the ''as-is'' state of their pipeline and any potential or actual threats. This information is required to comply with § 195.401(a), which states that no operator may operate or maintain its pipeline systems at a level of safety lower than that required by subpart F of 49 CFR part 195 and the procedures it is required to establish under § 195.402(a). Therefore, PHMSA expects operators will already be performing a level of risk analysis on non-HCA lines as well as HCA lines.

[43] Jeff Gottlieb: ''Phillips 66 oil line in Wilmington blamed for 1,200-gallon spill,'' Los Angeles Times, March 18, 2014. *http://articles.latimes.com/2014/mar/18/local/la-me-0319-crude-oil-20140319.*

E. IM and Non-IM Repair Criteria

1.a PHMSA's Proposal for § 195.452 (IM Repairs)

In the NPRM, PHMSA proposed modifying criteria in § 195.452(h) for IM repairs to:

- Categorize bottom-side dents with stress risers, pipe with significant stress corrosion cracking, and pipe with selective seam weld corrosion as immediate repair conditions;
- Require immediate repairs whenever the calculated burst pressure is less than 1.1 times MOP;
- Eliminate the 60-day and 180-day repair categories; and
- Establish a new, consolidated 270-day repair category.

1.b PHMSA's Proposal for § 195.422 (Non-IM Repairs)

PHMSA also proposed to amend the requirements in § 195.422 for performing non-IM repairs by:

- Applying the criteria in the immediate repair category in § 195.452(h); and
- Establishing an 18-month repair category for hazardous liquid pipelines that are not subject to IM requirements.

2. Summary of Public Comment

Citizen groups and individuals expressed concern with the changes to the repair timeline categories. The Alliance for Great Lakes et al. requested that PHMSA maintain the 180-day repair timeframe for all repairs that are not classified as immediate, and the Pipeline Safety Trust (PST) did not see justification for the 18-month and ''reasonable'' time frames added for repairing pipelines outside of HCAs. API–AOPL requested a reasonable timeframe to address repairs in offshore pipelines that considers the type of repair and permit that might be involved. ETP recommended that PHMSA change the 270-day and 18-month criteria to 1-year and 2-year criteria to assist operators with planning, budgeting, and scheduling.

Enterprise Products Partners suggested specific language to clarify that § 195.422 would apply only to pipelines not subject to IM requirements in § 195.452 and those determined not to have the potential to affect HCAs.

API–AOPL also expressed concern that PHMSA might apply these criteria beyond non-HCA transmission lines to gravity and gathering lines located offshore and recommended explicit language to state that § 195.422 does not apply to gravity or gathering lines. The GPA requested that PHMSA clarify the applicability of this section to out-of-service, ''idle'' pipelines.

Commenters also asked for additional standards for conditions triggering repairs. For example, one public safety organization requested a more stringent standard for the amount of metal loss that triggers ''immediate repair,'' whereas the Alliance for Great Lakes et al. recommended that PHMSA establish standards for the prevention, detection, and remediation of significant stress corrosion cracking and stress corrosion cracking.

The IPAA commented that PHMSA did not address whether resources exist to make the additional repairs that would be required, nor did it demonstrate a nexus between existing risk and the more conservative repair requirements that justify the potential costs, especially when considering regulated gathering lines. The GPA requested documentation on the basis for requiring the same repair criteria for non-gathering lines as the repair criteria for pipelines affecting HCAs. Western Refining recommended that PHMSA exempt pipeline segments that normally operate at a low pressure from the pressure reduction requirement. API–AOPL recommended that PHMSA add an immediate repair condition for crack anomalies at a 70 percent nominal wall thickness and an 18-month repair condition on dents with corrosion. API–AOPL also recommended that PHMSA include a ''Scheduled Conditions'' repair condition for non-HCA lines, which would require an operator to make a report prior to the year when a calculation of the predicted remaining strength of the pipe (including allowances for growth and tool measurement error) shows a predicted burst pressure at less than 1.1 times the MOP at the location of the anomaly. This recommendation aimed to mitigate the potential for pressure-limiting, immediate features before the next ILI. Enterprise Products Partners recommended language to provide operators with flexibility to determine the severity of the reported metal loss indication and its potential impact on the integrity of the pipeline by setting the dent threshold as corroded areas deeper than 20 percent of the nominal wall thickness or where an engineering analysis indicates a reduction in the safe operating pressure of the dented area.

API–AOPL and AGA recommended eliminating the SCC and SSWC immediate repair criteria. The AGA also requested that PHMSA allow pipeline operators to prioritize the repair of HCA segments over non-HCA segments. The GPA was also concerned that PHMSA's definition of SCC was based on the use of the word ''significant,'' because the term is subjective and PHMSA's proposed descriptors do not include all the variables that influence SCC behavior and is therefore very incomplete for assigning an ''actionable'' status for all instances.

The PST requested that PHMSA change § 195.563(a) to require that constructed, relocated, replaced, or otherwise changed pipelines must have cathodic protection within 6 months instead of 1 year, and they also requested that PHMSA require operators to know what type of pipe is in the ground and set the MOP appropriately, or test the pipe with an appropriate hydrotest to demonstrate a safe MOP.

During the meeting of February 1, 2016, the LPAC recommended that PHMSA modify the NPRM to include recognized industry engineering analysis regarding dents and cracks to determine they are non-injurious and do not require immediate repair, and to give full and equal consideration to the stakeholder comments that were considered during the LPAC discussion.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters. PHMSA proposed revisions to the IM repair criteria to provide operators greater flexibility regarding the repair timeframes for certain anomalies, provide additional clarification regarding specific anomaly types, and address pipe cracking issues both the agency and the NTSB had identified following the incident near Marshall, MI, especially regarding stress corrosion cracking and selective seam weld corrosion. PHMSA also proposed to apply these changes with some modifications to non-HCAs to provide flexibility to operators and allow the risk-based prioritization of repairs.

PHMSA notes that the LPAC, with certain suggestions, found the changes to both the non-HCA repair criteria and the HCA repair criteria to be cost-effective, practicable, and technically feasible provisions, and these provisions seemed to have wide stakeholder support following the ANPRM stage. However, PHMSA determined as part of the review process that it needs to gather additional data, including with respect to cost-benefit information, and to assess new technologies and practices before promulgating the proposed changes for non-HCA pipelines in this final rule. Based on this, PHMSA has decided to separate the repair-criteria provisions from this final rule and intends to issue a supplemental notice of proposed rulemaking where PHMSA would further analyze developing technology and practices, anomaly types and repair timeframes, and engineering critical assessment methods. This path will also provide commenters an additional opportunity to provide input on an important part of the regulations. PHMSA will incorporate any relevant discussion it would have included in this section of this rulemaking when discussing repair criteria in the supplemental notice. Therefore, for the purposes of this final rule, PHMSA is retaining the existing non-IM repair language at § 195.401(b)(1) and the existing IM repair language at § 195.452(h).

For non-IM pipelines, §§ 195.401(b)(1), 195.585, and 195.587 outline the requirements for non-integrity management pipeline repairs. Section 195.401(b)(1) requires operators that discover any condition that could adversely affect the safe operation of its pipeline system, they must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition. For IM pipelines, PHMSA expects operators to continue to follow the existing regulations in §§ 195.401(b)(2) and 195.452(h) as they are written and repair the listed anomaly types within the specified timeframes.

F. Leak Detection Requirements

1. PHMSA's Proposal

With respect to new hazardous liquid pipelines, PHMSA proposed to amend § 195.134 to require that all new lines be designed to have leak detection systems, including pipelines located in non-HCA areas.

With respect to existing pipelines, 49 CFR part 195 contains mandatory leak detection requirements for only those hazardous liquid pipelines that could affect an HCA. Congress included additional requirements for leak detection systems in section 8 of the 2011 Pipeline Safety Act. That legislation requires the Secretary to submit a report to Congress, within 1 year of the enactment date, on the use of leak detection systems, including an analysis of the technical limitations and the practicability, safety benefits, and adverse consequence of establishing additional standards for the use of those systems. Congress authorized the issuance of regulations for leak detection if warranted by the findings of the report.

Based on information available to PHMSA including post-accident reviews and the Kiefner Report, PHMSA believes the need to strengthen the requirements for leak detection systems is clear. In addition to modifying § 195.444 to require a means for detecting leaks on all portions of a hazardous liquid pipeline system including non-HCA areas, PHMSA proposed that operators perform an evaluation to determine what kinds of systems must be installed to adequately protect the public, property, and the environment. The proposed amendment to § 195.11 extended these new leak detection requirements to regulated onshore gathering lines.

2. Summary of Public Comment

Trade organizations expressed concerns with requiring operators of gathering lines and certain non-gathering lines to install and maintain leak detection systems. The GPA commented that PHMSA's proposal is not appropriate for gathering lines at this time, citing findings of the ''Liquids Gathering Pipelines: A Comprehensive Analysis'' study,[44] which concluded that (1) gathering lines present unique challenges to leak detection technologies; (2) gathering lines are constantly transition in flow, pressure, and line-packing; (3) benefits do not justify the cost for leak detection systems applied to gathering lines; and (4) there is a lack of demonstrated technology to reliably detect spills. The IPAA noted that PHMSA should not proceed with expanding leak detection systems because it had not performed an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems. The GPA also recommended that PHMSA provide relief for short sections of pipeline less than 1 mile in length and lines located within facilities where they pose no risk to the public. API–AOPL and OOC requested clarification that this section would not apply to offshore gathering lines. The commenters requested implementation periods ranging between 5 years (API–AOPL) and 7 years (GPA). Finally, the Texas Pipeline Association commented on the cost of complying with this regulation for lines outside of HCAs and the redirection of resources from high-risk areas to lower-risk areas that they allege would occur.

Citizen groups and other commenters requested minimum standards for leak detection systems, and applicability to all hazardous liquids lines. The Pipeline Safety Coalition recommended the inclusion of (1) all existing hazardous liquids lines and all lines under construction at rulemaking; (2) prescriptive standards for leak detection classifications; (3) prescriptive standards for acceptable leak detection procedures and devices; and (4) standards that are specific to location, community, and environmentally sensitive areas. The Alliance for Great Lakes et al. commented that computational pipeline monitoring systems detect only large ruptures and involve significant data interpretation and analysis. They expressed concerns regarding the lack of system standards and guidance on how to assess the effectiveness of a given leak detection system on a given pipeline due to significant variations in pipeline design. The Environmental Defense Center also recommended that automatic shutdown systems be required.

Beyond requirements for new pipelines, some commenters also requested a clear schedule for leak detection system for pipelines undergoing construction. For example, the NTSB urged PHMSA to include language that specifies a distinct trigger date for leak detection implementation on pipelines that have already started construction but would not yet be operational when the new regulation becomes effective.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA modify the NPRM to (1) provide a 5-year implementation period for existing pipelines and a 1-year implementation period for new pipelines and (2) clarify that the expanded use of leak detection systems is not applicable to offshore gathering pipelines.

3. PHMSA Response

PHMSA notes that commenters asserting PHMSA lacks the authority to require leak detection systems because it did not first conduct a study of these systems are incorrect. PHMSA did perform a leak detection study (''Leak Detection Study—DTPH56–11–D000001''[45]), as required by section 8 of the 2011 Pipeline Safety Act, and submitted this study to Congress on December 31, 2012. The study examined what methods and measures operators were using as leak detection systems and the limitations of those methods and measures. The study noted that ''due to the vast mileage of pipelines throughout the Nation, it is important that dependable leak detection systems are used to promptly identify when a leak has occurred so that appropriate response actions are initiated quickly. The swiftness of these actions can help reduce the consequences of accidents or incidents to the public, environment, and property.'' The study also noted that ''incidents described as leaks can also have reported large release volumes.'' Based on the results of the study, and due to pipeline accidents such as those near Marshall, MI, and Salt Lake City, UT, which the study referenced, PHMSA concluded that operators need to have an adequate means for identifying leaks to better protect the public, property, and the environment. PHMSA continues to foster leak detection technology improvements through research and development projects, and PHMSA is also considering pursuing rupture detection metrics in another rulemaking.

Recognizing that leak detection technology can be unreliable does not imply that monitoring and leak detection are without value. The value of lost product, negative impacts to the environment, loss of pipeline functionality, spill remediation costs, and public perception all impact decisions regarding the implementation of leak detection systems. It is difficult to assign costs to many of these items. PHMSA expects that the implementation of leak detection systems on non-HCA pipelines will accelerate leak detection, lead to faster response and spill containment, and reduce damages from hazardous liquid releases.

Given this information, PHMSA is finalizing a rule that requires all new and existing lines, except for gathering lines not subject to IM, regulated rural gathering lines, and offshore lines, to implement leak detection systems. Since all lines within HCAs are already subject to this requirement, the final rule affects pipelines outside of HCAs.

[44] Energy and Environmental Research Center, University of North Dakota, 2015, *https://www.undeerc.org/bakken/pdfs/EERC%20Gathering%20Pipeline%20Study%20Final%20Dec15.pdf.*

[45] Kiefner & Associates, Inc.: ''Leak Detection Study,'' Final Report No. 12–173, DTPH56–11–D–000001, December 10, 2012. *http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Press%20Release%20Files/Leak%20Detection%20Study.pdf.*

Commenters and LPAC members made persuasive arguments regarding the technical challenges that exist for implementing leak detection systems on offshore gathering lines due to the complex network of gathering lines coming from offshore platforms and tremendous fluctuations in flow controlled directly by production platforms. Further, commenters had concerns that there was not adequate justification for leak detection requirements on regulated rural gathering lines due to the lack of incident history. PHMSA did not receive any data or comments that contradicted these assertions; therefore, PHMSA is not extending leak detection requirements to offshore gathering lines or regulated rural gathering lines at this time. However, PHMSA does note that the LPAC had no objections to extending this requirement to regulated rural gathering lines and found the provision to be a cost-effective, practicable, and technically feasible provision. Further, during the 12866 meeting between OIRA and API on December 12, 2016, API presented data stating that operators agree with PHMSA's assumptions regarding the use of leak detection systems on non-HCA pipelines. As such, PHMSA may consider extending leak detection requirements to these lines in the future.

PHMSA considered input from the comments and from the LPAC in setting compliance periods of 1 year for all new lines, and 5 years for all existing lines. Regarding concerns about compliance periods for pipelines under construction, PHMSA considers any line that becomes operational after the publication of this rule to be a new line and will have 1 year to comply. PHMSA will consider pipelines that are already operational before the publication of this rule as existing lines, and those will have 5 years to comply. PHMSA determined that the specified timelines are reasonable and practicable given that many operators already implement leak detection systems on their entire network across both HCA and non-HCA miles, and because many operators are constructing and designing new lines with leak detection system capabilities. Further, PHMSA assumes that the cost of extending existing capabilities to non-HCA miles is minimal for systems already equipped with SCADA sensors (see the RIA for details).

Certain commenters questioned the methods of leak detection that PHMSA would require to comply with this provision. PHMSA notes that negative pressure wave monitoring, real-time transient modelling, or other external systems are not necessarily required to comply with the rule. The costs of using or installing these leak detection system components were not explicitly analyzed in the RIA; however, operators may voluntarily choose to use these components, as well as any others, to comply with the leak detection requirements of the rule.

PHMSA received several comments regarding leak detection system performance criteria, valve spacing requirements, and automatic shutdown capability, which were topics listed in the ANPRM. Due to the complexity of these topics and the need for further study and public comment, PHMSA is pursuing these topics in a separate rulemaking.[46]

G. Increased Use of ILI Tools in HCAs

1. PHMSA's Proposal

PHMSA proposed to require that all hazardous liquid pipelines in HCAs and areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless the basic construction of a pipeline will not accommodate the passage of such a device. The current requirements for the passage of ILI devices in hazardous liquid pipelines are prescribed in § 195.120, which require that new and replaced pipelines be designed to accommodate in-line inspection tools. Section 60102(f)(1)(B) of the Pipeline Safety Laws allows the requirements for the passage of ILI tools to be extended to existing hazardous liquid pipeline facilities, provided the basic construction of those facilities can be modified to permit the use of smart pigs.

2. Summary of Public Comment

Trade organizations expressed concern that the NPRM would inhibit operators from exercising their expert judgement in selecting an assessment method and would be overly burdensome. API–AOPL and other industry representatives requested that PHMSA not adopt this proposal because it would require pipelines to incur extensive costs due to age, design, and location of the pipelines, without demonstrating commensurate benefits. They also requested that PHMSA remove the requirement to petition for an exemption under § 190.9 and instead continue to allow operators to exercise their expertise and engineering judgment in using the most effective and efficient methods of evaluating the integrity of their facilities with prior notification to OPS.

[46] ''Pipeline Safety: Amendments to Parts 192 and 195 to Require Valve Installation and Minimum Rupture Detection Standards,'' RIN: 2137–AF06.

The IPAA and the American Gas Association (AGA) requested that PHMSA review current studies or conduct an original study to determine if ILI is appropriate to monitor pipeline corrosion given the current state of technology. The AGA also requested that PHMSA provide additional information on what the term ''basic construction'' meant in the exemption from the ILI-capable requirement.

Conversely, citizen groups and individuals recommended that operators use ILI more broadly. An organization representing public safety and other commenters expressed concern with the length of the 20-year implementation period and the multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated. Some of these commenters recommended instead that: (1) PHMSA significantly reduce the timing of accommodating ILI devices, perhaps to 5 years; (2) PHMSA require all new pipelines constructed in HCAs to accommodate ILI devices immediately; (3) PHMSA reexamine and tighten proposed exemptions; and (4) PHMSA establish standards for ILI tools, including the detection of stress corrosion cracking. Congresswoman Capps suggested that PHMSA could establish a shorter time frame of 5 years with an extension possible upon request with sufficient evidence for need and a provided plan of action to meet the standard. The PST recommended that operators integrate close interval survey results into ILI device findings.

Other groups commented on the tools used for inspection, the compliance periods, and accountability. The Environmental Defense Center requested that PHMSA require other inspection tools and methods, such as hydrostatic pressure testing, where operators detect certain types of anomalies and when these technologies can provide additional information regarding the condition and vulnerabilities of a pipeline system. The Alliance for Great Lakes et al. recommended that PHMSA develop a framework that assigns different compliance periods for pipelines based on factors such as age, leak history, corrosion, environmental circumstances that could affect the pipeline, and other aspects such as those typically reviewed in IM studies. Finally, California Assembly Member Das Williams requested that operators be required to submit ILI data to PHMSA for review and verification.

The NTSB recommended that PHMSA require owners/operators to develop comprehensive implementation plans with transparent progress reporting of intermediate milestones to best ensure operators modify existing pipelines to accommodate the passage of ILI devices within the 20-year time limit. The NTSB also recommended that operators modify all newly identified HCA segments to accommodate an internal inspection tool according to an accelerated schedule, but not more than 5 years after an operator identifies the HCA.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA adopt the proposed 20-year implementation period as feasible and cost-effective. In a separate vote, the LPAC reached a tie on a 10-year implementation period, which resulted in a failed motion. The LPAC also recommended that § 195.452(n) be modified to allow an operator to file a petition that ILI tools cannot be accommodated when the operator determines it would abandon or shut down a pipeline as a result of the cost to comply.

3. PHMSA Response

PHMSA carefully considered input from commenters and the LPAC in finalizing this rule, which requires that all HCA pipelines whose basic construction would accommodate ILI tools be modified to permit the use of ILI tools within 20 years. Examples of ''basic construction'' that an operator may be able to show would not accommodate ILI tools include short length, small diameter, diameter changes, low operating pressure, low-volume flow, location, sharp bends, and terrain. PHMSA shares the interest of commenters who requested expeditious upgrades to the pipeline network to accommodate ILI tools. PHMSA maintains that ILI tools are generally more effective than other methods at detecting integrity issues. ILI tools take advantage of state-of-the-art technological developments and allow operators to identify anomalies and prioritize anomalies without interrupting services. ILI tools also provide a higher level of detail than is possible using other testing tools such as hydrotesting, which allow operators to determine whether a required safety margin is met (*i.e.,* pass/fail) but do not provide information about the existence of anomalies that could deteriorate over time between tests. PHMSA notes that the existing regulation already requires new pipelines to be capable of accommodating ILI tools, as certain commenters requested. Data from operators' pipeline annual reports suggest that the vast majority of pipeline miles are currently assessed using ILI tools. The mileage not assessed using these tools is likely to consist of pipeline segments, such as small diameter pipes, where ILI is impracticable using the current technologies. Providing sufficient time for ILI tool accommodation projects allows the industry to prioritize these projects based on age or other factors, including the risk factors identified by the Alliance for the Great Lakes in their comments; it also reduces the mileage of pipeline potentially needing to be replaced before they have reached their operational life. PHMSA determined that a 20-year timeline strikes the appropriate balance between the need to make upgrades as soon as possible to enable more effective integrity assessment technologies, with the costs and operational practicalities of making those changes. Given that a preponderance of HCA pipelines can already accommodate ILI tools, exceptions available for specific pipeline designs, operational benefits of ILI over other assessment methods, the continued aging of unpiggable lines, and the 20-year compliance deadline that will further reduce remaining mileage of old pre-ILI pipeline, PHMSA determined that the final rule requirement to make existing HCA pipelines able to accommodate ILI tools is unlikely to impact any amount of the hazardous liquid pipeline infrastructure.[47] Accordingly, PHMSA does not estimate any cost for this requirement.

PHMSA will consider modifying its annual report form to have hazardous liquid pipeline operators report data on what percentages of their lines are piggable. In response to commenters who sought more immediate implementation, PHMSA notes that inability to use ILI on a pipeline segment does not mean that an operator has not assessed the pipeline; the regulation requires that these pipelines be assessed using alternative approaches, with hydrotesting being the most common alternative. Data reviewed by PHMSA indicates that less than 1 percent of HCA pipeline mileage is assessed using direct assessment methods. Comments about seismicity considerations are addressed in the next section.

In response to commenters who requested a specific deadline for making lines in newly identified HCAs capable of accommodating ILI tools, PHMSA notes that operators will have until the end of the 20-year implementation period to make lines piggable. Operators who newly identify HCAs in years 16–20 of the implementation period and after the 20-year implementation period will have 5 years from the date of the HCA identification to make lines in those areas piggable.

[47] In the RIA, PHMSA estimates that over 98 percent of pipelines for which ILI is applicable likely are already able to accommodate ILI tools. Given the factors listed here, PHMSA assumes that essentially all HCA lines for which ILII is practicable are currently, or will be within the next 20 years, piggable. Further details are in the RIA for this rulemaking.

H. Clarifying Other Requirements

1. PHMSA's Proposal

PHMSA also proposed several other clarifying changes to the regulations that were intended to improve compliance. First, PHMSA proposed to revise paragraph (b)(1) of § 195.452 to better harmonize the current regulations. The existing § 195.452(b)(2) requires that segments of new pipelines that could affect HCAs be identified before the pipeline begins operations and § 195.452(d)(1) requires that baseline assessments for covered segments of new pipelines be completed by the date the pipeline begins operation. However, § 195.452(b)(1) does not require an operator to draft its IM program for a new pipeline until 1 year after the pipeline begins operation. Improved consistency would be beneficial, as the identification of could affect segments and the performance of baseline assessments are elements of the written IM program. PHMSA proposed to amend the table in (b)(1) to resolve this inconsistency by eliminating the 1-year compliance deadline for Category 3 pipelines. An operator of a new pipeline would be required to develop its written IM program before the pipeline begins operation.

PHMSA proposed to add additional specificity to § 195.452(g) by establishing several pipeline attributes that must be included in IM information analyses and to explicitly require that operators integrate analyzed information to help ensure they are properly evaluating interacting threats. PHMSA also proposed that operators explicitly consider any spatial relationships among anomalous information.

PHMSA also proposed that operators verify their segment identification annually by determining whether factors considered in their analysis have changed. The change that PHMSA proposed would not require that operators automatically re-perform their segment analyses. Rather, it would require operators to identify the factors considered in their original analyses, determine whether those factors have changed, and consider whether any such change would be likely to affect the results of the original segment identification. If so, the operator would be required to perform a new segment analysis to validate or change the endpoints of the segments affected by the change.

PHMSA also proposed to add an explicit reference clarifying that the IM requirements apply to portions of pipeline facilities other than line pipe. Unlike integrity assessments for line pipe, § 195.452 does not include explicit deadlines for completing the analyses of other facilities within the definition of ''pipeline'' or for implementing actions in response to those analyses. While most operators correctly treat any component that product moves through in areas that could affect HCAs as subject to IM, PHMSA has reason to believe that some operators have not completed analyses of their non-pipe facilities such as pump stations and breakout tanks and have not implemented appropriate protective and mitigative measures.

Section 29 of the 2011 Pipeline Safety Act states that ''[i]n identifying and evaluating all potential threats to each pipeline segment pursuant to parts 192 and 195 of title 49, Code of Federal Regulations, an operator of a pipeline facility shall consider the seismicity of the area.'' While seismicity is already mentioned at several points in the IM program guidance provided in Appendix C of part 195, PHMSA proposed to further comply with Congress's directive by including an explicit reference to seismicity in the list of risk factors that must be considered in establishing assessment schedules (§ 195.452(e)), performing information analyses (§ 195.452(g)), and implementing preventive and mitigative measures (§ 195.452(i)) under the IM requirements.

2. Summary of Public Comment

Trade organizations commented primarily on the implementation period for PHMSA's clarifications on data integration and the attributes and information required. Other trade associations joined API–AOPL in requesting a 5-year implementation schedule for integrating these specific attributes, including populating data into information systems and validating the quality of the data process. The AGA recommended that PHMSA focus on the analysis of information and attributes rather than their integration.

Trade organizations also requested flexibility in developing the attributes and information required in data analysis. The AGA requested that operators independently develop the list of information and attributes to be included in data analysis. They also commented that there is no current regulatory requirement for an operator of hazardous liquid or natural gas pipelines to maintain or utilize a GIS.

Finally, trade organizations expressed concern with changes to the baseline assessment of newly constructed pipelines. API–AOPL requested that PHMSA clarify that hydrostatic testing is an acceptable method of meeting this requirement for new construction.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA modify the NPRM to require data integration to begin in year one, with all attributes completed within 3 years.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters. As discussed at the LPAC meeting, integrating data is a key element and concept of continuous improvement and IM. The requirement that operators perform data integration has long been a part of IM program requirements. The attributes that PHMSA proposed in the NPRM were factors operators should have already been considering when assessing risk to their pipelines—PHMSA is merely codifying them to better ensure all operators are utilizing them. PHMSA understands that the need for some operators to enhance their data systems to fit these specific attributes will take some time and effort. Because of this, PHMSA agrees with the LPAC that operators should be given a maximum of 3 years to fully comply and integrate all the proposed attributes into their data integration systems, with implementation beginning once the rule is published. However, this implementation period does not mean operators should lapse in what they are currently required to perform under § 195.452(g). PHMSA expects operators to add the attributes issued in this final rule to their current data integration systems and efforts. While PHMSA is sympathetic to allowing operators more flexibility with the attributes that should be considered for data integration, experience has shown that PHMSA needs to prescribe a common baseline set of attributes for operators to assess.

PHMSA agrees with commenters who believe hydrostatic testing is an acceptable baseline assessment method for newly constructed pipelines and is incorporating that option into this final rule. As operators are required to conduct hydrostatic tests on all newly constructed pipelines prior to operation, and PHMSA allows operators to use hydrostatic testing for subsequent assessments, PHMSA has determined this could eliminate additional duplicative baseline assessments and reduce operator burden.

V. PIPES Act of 2016

On June 22, 2016, the President signed the PIPES Act of 2016, Public Law 114–183, containing Sections 14 and 25, ''Safety Data Sheets'' and ''Requirements for Certain Hazardous Liquid Pipeline Facilities,'' respectively. The language in both Section 14 and Section 25 is self-executing, with Section 25 specifically amending the Pipeline Safety Act at 49 U.S.C. 60109 by adding new paragraphs (g) through (g)(4). To allow the timely implementation of these sections of the PIPES Act of 2016 and to help ensure regulatory certainty, PHMSA has determined that good cause exists for finding that notice and comment on these provisions is impracticable and contrary to the public interest and is subsequently incorporating them into this final rule.

Section 14 of the PIPES Act of 2016 requires owners and operators of hazardous liquid pipeline facilities, following accidents involving pipeline facilities that result in hazardous liquid spills and within 6 hours of a telephonic or electronic notice of the accident to the National Response Center, to provide safety data sheets on any spilled hazardous liquid to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders. PHMSA has incorporated this requirement in a new § 195.65 under the reporting requirements of Subpart B.

Section 25 of the PIPES Act of 2016 applies to operators of any underwater hazardous liquid pipeline facility located in an HCA that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water. Operators of these facilities, notwithstanding any pipeline integrity management program or integrity assessment schedule otherwise required by the Secretary, must ensure that pipeline integrity assessments using internal inspection technology appropriate for the pipeline's integrity threats are completed not less often than once every 12 months; and using pipeline route surveys, depth of cover surveys, pressure tests, ECDA, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, ensure that pipeline integrity assessments are completed on a schedule based on the risk that the pipeline facility poses to the HCA in which the pipeline facility is located. PHMSA has incorporated these requirements in a new § 195.454 as an addition to the pipeline integrity management requirements under subpart F.

VI. Section-by-Section Analysis

§ 195.1 Which pipelines are covered by this part?

Section 195.1(a) lists the pipelines that are subject to the requirements in 49 CFR part 195, including gathering lines that cross waterways used for commercial navigation as well as certain onshore gathering lines (*i.e.,* those that are in a non-rural area, that meet the definition of a regulated onshore gathering line, or that are in an inlet of the Gulf of Mexico). PHMSA has determined it needs additional information about unregulated gathering lines to fulfill its statutory obligations, and it has determined it needs additional information about gravity lines to determine whether any safety regulations need to be extended to these lines as well. Accordingly, this final rule extends the reporting requirements in subpart B of part 195 to all gravity and gathering lines (whether regulated, unregulated, onshore, or offshore).

§ 195.2 Definitions

Section 195.2 provides definitions for various terms used throughout part 195. On August 10, 2007, PHMSA published a policy statement and request for comment on the transportation of ethanol, ethanol blends, and other biofuels by pipeline (72 FR 45002). PHMSA noted in the policy statement that the demand for biofuels was projected to increase in the future because of several Federal energy policy initiatives, and that the predominant modes for transporting such commodities (*i.e.,* truck, rail, or barge) would expand over time to include greater use of pipelines. PHMSA also stated that ethanol and other biofuels are substances that ''may pose an unreasonable risk to life or property'' within the meaning of 49 U.S.C. 60101(a)(4)(B) and accordingly these materials constitute ''hazardous liquids'' for purposes of the pipeline safety laws and regulations.

PHMSA is modifying the definition of ''hazardous liquid'' in § 195.2 to conform with 49 U.S.C. 60101(a)(4)(B) and clarify that the transportation of biofuel by pipeline is subject to the requirements of 49 CFR part 195.

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

The incorporation by reference of NACE SP0102 and API RP 1130 was previously approved by the Director of the Federal Register and is not changed by this rule.

Section 195.13 What requirements apply to pipelines transporting hazardous liquids by gravity?

Section 195.13 is added to subject gravity lines to the same annual, accident, and safety-related condition reporting requirements in subpart B of part 195 as other hazardous liquid pipelines.

Section 195.15 What reporting requirements apply to reporting-regulated-only gathering lines?

Section 195.15 is added to subject otherwise unregulated rural gathering lines and certain offshore lines in State waters to the annual, accident and safety-related condition reporting requirements in subpart B of part 195 as other hazardous liquid pipelines.

Section 195.65 Safety Data Sheets

Section 195.65 contains the requirements for providing safety data sheets on spilled hazardous liquids following accidents. In accordance with Section 14 of the PIPES Act of 2016, PHMSA is requiring owners and operators of hazardous liquid pipeline facilities, following accidents that result in hazardous liquid spills, to provide safety data sheets on those spilled hazardous liquids to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center. This is a self-executing provision from the PIPES Act of 2016 that PHMSA is incorporating into subpart B of the hazardous liquid pipeline safety regulations.

Section 195.120 Passage of Internal Inspection Devices

Section 195.120 contains the requirements for accommodating the passage of internal inspection devices in the design and construction of new or replaced pipelines. PHMSA has decided that, in the absence of an emergency, or where the basic construction makes that accommodation impracticable, a pipeline should be designed and constructed to permit the use of ILIs. Accordingly, this final rule repeals the provisions in the regulation that allow operators to petition the Administrator for a finding that the ILI compatibility requirement should not apply as a result of construction-related time constraints and problems. The other provisions in § 195.120 are re-organized without altering the existing substantive requirements.

Section 195.134 Leak Detection

Section 195.134 contains the design requirements for computational pipeline monitoring leak detection systems. The final rule restructures the existing requirements into paragraphs (a) and (c) and adds a new provision in paragraphs (b) and (d) to ensure that all newly constructed, covered pipelines are designed to include leak detection systems based upon standards in section 4.2 of API 1130 or other applicable design criteria in the standard.

Section 195.401 General Requirements

Section 195.401 prescribes general requirements for the operation and maintenance of hazardous liquid pipelines. PHMSA is modifying the pipeline repair requirements in § 195.401(b). PHMSA is retaining, without change, the requirements in paragraphs (b)(1) for non-IM repairs and (b)(2) for IM repairs. A new paragraph (b)(3) is added, however, to clearly require operators to consider the risk to people, property, and the environment in prioritizing the remediation of any condition that could adversely affect the safe operation of a pipeline system, no matter whether those conditions are in HCAs or non-HCAs.

Section 195.414 Inspections of Pipelines in Areas Affected by Extreme Weather and Natural Disasters

Extreme weather and natural disasters can affect the safe operation of a pipeline. Accordingly, this final rule establishes a new § 195.414 that requires operators to perform inspections after these events and to take appropriate remedial actions.

Section 195.416 Pipeline Assessments

Periodic assessments, particularly with ILI tools, provide critical information about the condition of a pipeline, but are only currently required under IM requirements in §§ 195.450 through 195.452. PHMSA has determined that operators should be required to have the information needed to promptly detect and remediate conditions that could affect the safe operation of pipelines in all areas. Accordingly, the final rule establishes a new § 195.416 that requires operators to perform an assessment, at least once every 10 years, of onshore pipelines that can accommodate inline inspection tools and that are not already subject to the IM requirements. This assessment must be performed for the range of relevant threats to the pipeline segment using an appropriate ILI tool(s) and account for uncertainties in reported results. Operators must use a method capable of assessing seam integrity and corrosion and deformation anomalies when assessing LF–ERW pipe, lap-welded pipe, or pipe with a seam factor of less than 1.0. In lieu of performing an ILI assessment on their lines, operators can perform the assessment by using a pressure test, external corrosion direct assessment, or other technology (subject to prior notification, method being able to assess the threat, and ''no objection'' by PHMSA) that can be demonstrated as providing an equivalent understanding of the pipe's condition.

The regulation also requires that the results of these assessments be reviewed by a person qualified to determine if any conditions exist that could affect the safe operation of a pipeline; that such determinations be made promptly, but no later than 180 days after the assessment; that any unsafe conditions be remediated in accordance with the repair requirements in § 195.401(b)(1); and that all relevant information about the pipeline be considering in complying with the requirements of § 195.416. Consistent with the requirements in the revised § 195.452(h)(2) regarding the discovery of condition, in cases where the information necessary to make determination about pipeline threats cannot be obtained within 180 days following the date of inspection, pipeline operators must notify PHMSA and provide an expected date when adequate information will become available.

Section 195.444 Leak Detection

Section 195.444 contains the operation and maintenance requirements for Computational Pipeline Monitoring leak detection systems. PHMSA is amending the PSR so that all covered hazardous liquid pipelines have a leak detection system. Therefore, the final rule reorganizes the existing requirements of the regulation into paragraphs (a) and (c), and adds a new general provision in paragraph (b) that requires operators to have leak detection systems on all covered pipelines and to consider certain factors in determining what kind of system is necessary to protect the public, property, and the environment.

Section 195.452 Pipeline Integrity Management in High Consequence Areas

Section 195.452 contains the IM requirements for hazardous liquid pipelines that could affect a HCA in the event of a leak or failure. The final rule clarifies the applicability of the deadlines in paragraph (b) for the development of a written program for new pipelines and low-stress pipelines in rural areas. The rule also makes the following amendments to paragraphs (c) through (o):

- Paragraph (c)(1)(i)(A) is amended to ensure that operators consider uncertainty in tool tolerance in reviewing the results of ILI assessments. The paragraph is also amended to be more consistent with paragraphs at § 195.416 by stating that pipeline segments with identified or probable risks or threats related to cracks (such as at pipe body and weld seams) based on the risk factors specified in paragraph (e), an operator must use an ILI tool or tools capable of detecting crack anomalies.
- Paragraph (d) is amended to eliminate obsolete deadlines for performing baseline assessments and to clarify the requirements for newly identified HCAs. The deletion of these previous compliance dates does not change or delete any associated recordkeeping requirements or implement any new recordkeeping requirements. Operators should retain the records they have used to show compliance regarding the baseline assessment deadlines.
- Paragraph (e)(1)(vii) is amended to include local environmental factors, including seismicity, that might affect pipeline integrity.
- Paragraph (g) is amended to prescribe certain data points and criteria that operators must consider in performing the information analysis required to evaluate periodically the integrity of covered pipeline segments.
- Paragraph (h)(2) is amended to require that in those situations where an operator must obtain adequate information within 180 days after an integrity assessment to determine whether an anomalous condition could present a potential integrity threat of the pipeline but the operator believes it is impracticable to obtain sufficient information within that period, the operator must notify PHMSA and provide an expected date when adequate information will become available.
- Paragraph (j) is amended to establish a new provision for verifying the risk factors used in identifying covered segments on at least an annual basis, not to exceed 15 months.
- A new paragraph (n) is added to require that all pipelines in areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless, subject to a petition and PHMSA approval, the basic construction of a pipeline will not permit that accommodation, the existence of an emergency renders such an accommodation impracticable, or the operator determines it would abandon or shut down a pipeline as a result of the cost to comply with the requirement of this section. Paragraph (n) requires that pipelines in newly identified HCAs after the 20-year period be made capable of accommodating ILIs within 5 years of the date of identification or before the performance of the baseline assessment, whichever is sooner.
- Paragraph (o) is added to allow operators additional time to integrate the additional information and attributes that PHMSA has added to the information analysis required under paragraph (g)(1).
- Finally, an explicit reference to seismicity is added to factors that must be considered in establishing assessment schedules under paragraph (e), for performing information analyses under paragraph (g), and for implementing preventive and mitigative measures under paragraph (i).

Section 195.454 Integrity Assessments for Certain Underwater Hazardous Liquid Pipeline Facilities Located in HCAs

Section 195.454 contains additional assessment requirements for operators of any underwater hazardous liquid pipeline facility located in an HCA that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water. In accordance with section 25 of the PIPES Act of 2016, PHMSA is requiring these operators to ensure that they complete pipeline integrity assessments not less often than once every 12 months using internal inspection technology appropriate for the integrity threats to the pipeline and complete pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, on a schedule based on the risk that the pipeline facility poses to the HCA in which the pipeline facility is located. This is a self-executing provision from the PIPES Act of 2016 that PHMSA is incorporating into subpart F of the hazardous liquid pipeline safety regulations.

VII. Regulatory Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety

Law (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities, as delegated to the PHMSA Administrator under 49 CFR 1.97.

PHMSA is revising the ''Authority'' entry for part 195 to include a citation to a provision of the Mineral Leasing Act (MLA), specifically, 30 U.S.C. 185(w)(3). Section 185(w)(3) provides that ''[p]eriodically, but at least once a year, the Secretary of the Department of Transportation shall cause the examination of all pipelines and associated facilities on Federal lands and shall cause the prompt reporting of any potential leaks or safety problems.'' The Secretary has delegated this responsibility to PHMSA (49 CFR 1.97). PHMSA has traditionally complied with § 185(w)(3) through the issuance of its pipeline safety regulations, which require annual examinations and prompt reporting for all or most of the pipelines they cover. PHMSA is making this change to be consistent with and make clear its long-standing position that the agency complies with the MLA through the issuance of pipeline safety regulations.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

This final rule is a significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735), and therefore was reviewed by the Office of Management and Budget. This final rule is significant under the Regulatory Policies and Procedures of the Department of Transportation (44 FR 11034) because of substantial congressional, State, industry, and public interest in pipeline safety.

In the regulatory analysis, PHMSA discusses the alternatives to the amended requirements and, where possible, provides estimates of the benefits and costs for specific regulatory requirements by individual requirement areas. The regulatory analysis provides PHMSA's best estimate of the impact of the final rule requirements. As shown in the table below, PHMSA estimated the total annual costs of the rule at $19.5 million using a 3 percent discount rate and $21.4 million using a 7 percent discount rate.

Due to data limitations, PHMSA evaluated the benefits of the final rule qualitatively. Overall, the rule will provide direct benefits through avoiding damages from hazardous pipeline incidents that may be prevented through earlier detection of threats to pipeline integrity from corrosion or following extreme weather events, and through enhancing the ability of PHMSA and pipeline operators to evaluate risks. As context, operator-reported data for hazardous liquid incidents that occurred between 2010 and 2017 show reported average annual damages of $91.6 million for pipelines outside HCAs and $265.8 million for pipelines inside HCAs, or about $815 and $3,222 per mile of hazardous liquid pipeline, respectively. These damages are only a fraction of the total social costs of hazardous liquid releases but indicate the potential magnitude of benefits derived from preventing pipeline failures.

ANNUALIZED COSTS AND BENEFITS BY REQUIREMENT AREA (2017$) [48]

Final rule requirement area	Annual costs [1]		Benefits
	3% Discount rate	7% Discount rate	
1. Reporting requirements for gravity lines	$5,000	$5,000	Better risk understanding and management.[2]
2. Reporting requirements for gathering lines	$75,000	$76,000	Better risk understanding and management.[3]
3. Inspections of pipelines in areas affected by extreme weather events [4].	Minimal	Minimal	Additional clarity and certainty for pipeline operators.
4. Assessments of onshore pipelines that are not already covered under the IM program using ILI every 10 years [5] [6].	$6,467,000	$6,467,000	Avoided incidents and damages through detection of safety conditions.[7]
5. IM repair criteria [8]	$0	$0	$0.
6. LDSs on pipelines located outside HCAs [6]	$8,652,000	$10,508,000	Reduced damages through earlier detection and response.[9]
7. Increased use of ILI tools [10]	Minimal	Minimal	Improved detection of pipeline flaws.[10]
8. Clarify certain IM plan requirements.	$4,269,000	$4,343,000	Reduced damages through prevention and earlier detection and response.[11]
Total	$19,468,000	$21,399,000	Reduced damages from avoiding and/or mitigating hazardous liquid releases.

[1] Costs in this table are rounded to the nearest thousand dollars and may differ from costs presented in individual sections of the document. One-time costs are annualized over a 10-year period using discount rates of 3 percent and 7 percent.

[2] Gravity lines can present safety and environmental risks. Depending on the elevation change, a gravity flow pipeline could have more pressure than a pipeline with pump stations to boost the pressure. The benefits of this requirement are not quantified, but based on social costs of $51 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 101 gallons per year to generate benefits that equal the costs.

[3] The benefits are not quantified, but based on social costs of $51 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 1,493 gallons per year to generate benefits that equal the costs.

[4] To the extent that the 72-hour timeline required in the final rule results in higher costs for conducting inspections following a disaster (e.g., due to staff overtime), the final rule could result in costs not reflected in this analysis.

[5] PHMSA also conducted a sensitivity analysis that uses alternative baseline assumptions for pipelines not currently covered under the IM program. Specifically, PHMSA estimated the costs for two alternative scenarios: (1) A scenario that assumes that 100 percent of mileage outside HCAs is assessed in the baseline; and (2) a scenario that assumes that 83 percent of the mileage is assessed in the baseline. Costs for these two scenarios are $0 and $12.9 million, respectively.

[6] Excludes gathering lines.

[7] Given a cost per incident of $536,800, incremental assessment of pipelines outside of HCAs would need to prevent 12 incidents for benefits to equate costs.

[8] PHMSA is not finalizing any changes to the repair criteria and as such expects no incremental costs or benefits.

[48] Numbers in this table may not sum due to rounding.

[9] As discussed in Section 2.6.2, 1,918 incidents involved pipelines outside HCAs between 2010 and 2017, or an average of 240 incidents per year. Transmission pipeline incidents outside HCAs had average costs of approximately $382,179, not including additional damages and costs that are excluded or underreported in the incident data. The annual cost estimate is equivalent to the average damages of 28 to 32 such incidents.

[10] Costs (to retrofit pipes to accommodate ILI) and benefits (from avoided damages) would accrue only to the extent that existing practices deviate from industry standards; PHMSA expects costs and benefits will be minimal due to baseline prevalence of ILI-capable pipelines in all areas.

[11] The benefits of reduced costs associated with the prevention or reduction of released hazardous liquids cannot be quantified but could vary in frequency and size depending on the types of failures that are averted. Including additional pipelines in the IM plan, integrating data, and conducting spatial analyses is expected to enhance an operator's ability to identify and address risk. The societal costs associated with incidents involving pipelines in HCAs average $1.7 million per incident (see Section 2.6.2). The annual cost estimates for this requirement are equivalent to the average damages from less than three such incidents. This is relative to an annual average of 161 incidents in HCAs between 2010 and 2017.

Overall, factors such as increased safety, public confidence that all pipelines are regulated, quicker discovery of leaks and mitigation of environmental damages, and better risk management are expected to yield benefits that exceed or otherwise justify the costs. A copy of the final RIA has been placed in the docket. Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.,* the Office of Information and Regulatory Affairs designated this rule as not a ''major rule,'' as defined by 5 U.S.C. 804(2).

C. Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs

The final rule is an Executive Order 13771 regulatory action. Details on the estimated costs of this final rule can be found in the rule's economic analysis.

D. Executive Order 13132: Federalism

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism''). This final rule does not adopt any regulation that has substantial direct effects on the states, the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government. It does not adopt any regulation that imposes substantial direct compliance costs on state and local governments. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

E. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 (Pub. L. 96–354) (RFA) establishes ''as a principle of regulatory issuance that agencies shall endeavor, consistent with the objectives of the rule and of applicable statutes, to fit regulatory and informational requirements to the scale of the businesses, organizations, and governmental jurisdictions subject to regulation. To achieve this principle, agencies are required to solicit and consider flexible regulatory proposals and to explain the rationale for their actions to assure that such proposals are given serious consideration.''

The RFA covers a wide range of small entities, including small businesses, not-for-profit organizations, and small governmental jurisdictions. Agencies must perform a review to determine whether a rule will have a significant economic impact on a substantial number of small entities. If the agency determines that it will, the agency must prepare a regulatory flexibility analysis as described in the RFA.

However, if an agency determines that a rule is not expected to have a significant economic impact on a substantial number of small entities, section 605(b) of the RFA provides that the head of the agency may so certify and a regulatory flexibility analysis is not required. The certification must include a statement providing the factual basis for this determination, and the reasoning should be clear.

PHMSA performed a screening analysis of the economic impact on small entities. The screening analysis is available in the docket for the rulemaking. PHMSA estimates that compliance costs may exceed 1 percent of sales for 23 to 31 of the estimated small businesses and may exceed 3 percent of sales for 9 to 10 small businesses. The higher number of affected small businesses assumes that the operator incurs costs for all applicable requirements.

Given the small number and percentage of small businesses affected, the small sales test ratios, and the noted flexibility, PHMSA determined that the final rule will not have a significant impact on a substantial number of small entities.[49]

Therefore, I certify that this action does not have a significant economic impact on a substantial number of small entities.

F. National Environmental Policy Act

PHMSA analyzed this final rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR parts 1500 through 1508), and DOT Order 5610.1C, and has determined that this action will not significantly affect the quality of the human environment. An environmental assessment of this rulemaking is available in the docket.

[49] Based on SBA (2013), including criteria developed by other agencies.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments''). Because this final rule does not have Tribal implications and does not impose substantial direct compliance costs on Indian Tribal governments, the funding and consultation requirements of Executive Order 13175 do not apply.

H. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA estimates the proposals in this rulemaking will impact the following information collections:

''Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting'' identified under Office of Management and Budget (OMB) Control Number 2137–0047;

''Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities'' identified under OMB Control Number 2137–0578;

''Integrity Management in High Consequence Areas for Operators of Hazardous Liquid Pipelines'' identified under OMB Control Number 2137–0605;

''Pipeline Safety: Reporting Requirements for Hazardous Liquid Pipeline Operators: Hazardous Liquid Annual Report'' identified under OMB Control Number 2137–0614;

''National Registry of Pipeline and LNG Operators'' identified under OMB Control Number 2137–0627; and

''Operator Notifications—Alternate Pressure Testing Method'' identified under OMB Control Number 2137–0630.

PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this rule. These information collections are contained in the Federal Pipeline Safety Regulations, 49 CFR parts 190–199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. *Title:* Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting.

OMB Control Number: 2137–0047.

Current Expiration Date: 08/31/2020.

Abstract: This information collection covers the collection of information from owners and operators of hazardous liquid pipelines. To ensure adequate public protection from exposure to potential hazardous liquid pipeline failures, PHMSA collects information on reportable hazardous liquid pipeline accidents. 49 CFR 195.54 requires hazardous liquid operators to file an accident report, as soon as practicable, but not later than 30 days after discovery of the accident, on DOT Form 7000–1 whenever there is a reportable accident the characteristics of an operator's pipeline system. The final rule will require operators of both gravity lines and gathering lines to be subject to these accident reporting requirements. Thus, PHMSA expects an additional 28 HL pipeline operators (23 gathering line operators and approximately 5 gravity line operators) to be added to the reporting community.

If the frequency of accidents is the same for non-regulated gathering lines and gravity lines as it is for transmission lines, approximately 4 to 6 percent of these newly regulated operators will submit an accident report in any given year. Of the 23 new gathering line operators, PHMSA expects 5 accident reports to be filed per year. Of the 5 new gravity line operators, PHMSA expects 1 accident report to be filed per year. This results in an added burden of 6 new accident reports per year at 10 hours per report for a total added burden of 60 hours for accident reporting.

The final rule will also amend the Pipeline Safety Regulations (PSR) in 49 CFR 195.65 to require all owners and operators of hazardous liquid pipeline facilities, following accidents that result in hazardous liquid spills, to provide safety data sheets on those spilled hazardous liquids to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center. PHMSA expects hazardous liquid operators to file approximately 406 accident reports per year. This will result in an added burden of 406 new notifications per year. PHMSA expects that it will take operators 30 minutes to conduct the required task. This will result in an added burden of 406 records at .5 hours per record for a total added burden of 203 hours for safety data sheet notifications recordkeeping.

This information collection is being revised to account for the additional burden that will be incurred because of these new provisions.

Affected Public: Owners and operators of hazardous liquid pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,644.

Total Annual Burden Hours: 52,692.

Frequency of Collection: On occasion.

2. *Title:* Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities.

OMB Control Number: 2137–0578.

Current Expiration Date: 8/31/2022.

Abstract: 49 U.S.C. 60102 requires each operator of a pipeline facility (except master meter operators) to submit to U.S. DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazard to life, property or the environment.

This rule will require operators of both gravity lines and gathering lines to be subject to safety-related condition reporting. While there is no guarantee that each of the newly covered operators will incur a safety-related condition, it is a possibility. As a result, PHMSA plans to include an additional 28 hazardous liquid pipeline operators (23 gathering line operators and approximately 5 gravity line operators) in this reporting community. PHMSA estimates that it takes each operator 6 hours to complete a safety-related condition report. The addition of the 28 newly covered operators will result in 28 additional responses and an added burden of 168 hours (28 operators * 6 hours).

This information collection is being revised to account for the additional burden that will be incurred by newly regulated entities. Operators currently submitting annual reports will not be otherwise impacted by this rule.

Affected Public: Owners and operators of hazardous liquid pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 174.

Total Annual Burden Hours: 1,044.

Frequency of Collection: On occasion.

3. *Title:* Hazardous Liquid Pipeline Assessment Requirements.

OMB Control Number: 2137–0605.

Current Expiration Date: 09/30/2022.

Abstract: Owners and operators of hazardous liquid pipelines are required to have continual assessment and evaluation of pipeline integrity through inspection or testing, as well as remedial preventive and mitigative actions. Because of this rulemaking action, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, pipeline operators are required to notify PHMSA in writing and provide an expected date when adequate information will become available. PHMSA estimates that only 1 percent of repair reports (approx. 74) will require these notifications each year. Operators are authorized to send the notification, via email, to PHMSA's Information Resources Manager. PHMSA estimates that it will take operators 30 minutes to create and send each notification resulting in an overall burden increase of 37 hours annually.

Hazardous liquid pipeline operators are also required to notify PHMSA when they are unable to assess their pipeline via an in-line inspection. Operators who choose to use an alternate assessment method must demonstrate that their pipeline is not capable of accommodating an in-line inspection tool and that the use of an alternative assessment method will provide a substantially equivalent understanding of the condition of the pipeline. PHMSA estimates that operators will submit approximately 10 notifications each year regarding these conditions. Further, PHMSA estimates that each notification will take 10 hours, which includes the time to assemble the necessary information to demonstrate that the pipeline is not capable of accommodating an ILI tool and specify that the alternative assessment method will provide a substantially equivalent understanding of the pipeline. This will result in an annual notification burden of 100 hours.

The overall annual burden increase for this information collection is 84 responses and 137 hours. PHMSA requests the title of this information collection, previously ''Integrity Management in High Consequence Areas for Operators of Hazardous Liquid Pipelines,'' be changes to better align with the requested data.

Affected Public: Owners and operators of Hazardous Liquid Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 287.

Total Annual Burden Hours: 325,607.

Frequency of Collection: Annually.

4. *Title:* Pipeline Safety: Reporting Requirements for Hazardous Liquid Pipeline Operators: Hazardous Liquid Annual Report.

OMB Control Number: 2137–0614.

Current Expiration Date: 01/31/2022.

Abstract: Owners and operators of hazardous liquid pipelines are required to provide PHMSA with safety-related documentation relative to the annual operation of their pipeline. The provided information is used to compile a national pipeline inventory, identify safety problems, and target inspections.

Due to provisions within this final rule, approximately 5 gravity line operators and 23 gathering line operators will be required to submit annual reports to PHMSA. PHMSA estimates the burden associated with annual reporting activities to be approximately 19 hours per report, composed of 12 hours of a compliance officer's time and 7 hours of a secretary/administrative assistant's time. The newly regulated gravity and gathering line operators will cause an added burden of 28 new annual reports per year at 19 hours per report for a total added burden of 532 hours for annual reporting.

This information collection is being revised to account for the additional burden that will be incurred by the newly affected operators. Operators currently submitting annual reports will not be otherwise impacted by this rule.

Affected Public: Owners and operators of hazardous liquid pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 475.

Total Annual Burden Hours: 8,989.

Frequency of Collection: Annually.

5. *Title:* National Registry of Pipeline and LNG Operators.

OMB Control Number: 2137–0627.

Current Expiration Date: 04/301/2022.

Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse for the reporting requirements for an operator regulated under or subject to reporting requirements of 49 CFR parts 191, 192, 193, or 195. The final rule requires operators of both gravity lines and gathering lines to be subject to various reporting requirements. Thus, approximately 5 gravity line operators and 23 gathering line operators will be required to register their pipeline with the National Pipeline Registry and apply for an Operator Identification number (OPID). PHMSA estimates that this activity will take 1 hour per operator to register.

Gravity and gathering line operators will also be required to notify PHMSA of certain changes made to their pipeline system when applicable. PHMSA estimates that 5 percent (approximately 1) of these newly regulated operators will make these notifications each year. PHMSA estimates that this activity will take 1 hour per operator.

This information collection is being revised to account for the additional burden (29 responses × 1 hour = 29 hours) that will be incurred by the newly regulated operators. Operators currently registered will not be otherwise impacted by this rule.

Affected Public: Natural gas, LNG, and hazardous liquid pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 718.

Total Annual Burden Hours: 718.

6. *Title:* Hazardous Liquid Operator Notifications.

OMB Control Number: 2137–0630.

Current Expiration Date: N/A.

Abstract: The Pipeline Safety regulations contained within 49 CFR part 195 require hazardous liquid operators to notify PHMSA in various instances. 49 CFR 195.414 requires hazardous liquid operators who are unable to inspect their pipeline facilities within 72 hours of an extreme weather event to notify the appropriate PHMSA Region Director as soon as practicable. PHMSA expects to receive 100 of these notifications annually. PHMSA believes it will take operators approximately 15 minutes (0.25 hours) to make this notification and send it to the Regional Director electronically. PHMSA expects the annual burden for this requirement to be 25 hours.

49 CFR 195.452 requires operators of pipelines that cannot accommodate an in-line inspection tool to file a petition in compliance with 49 CFR 190.9. PHMSA expects to receive 10 of these notifications annually. PHMSA expects that it will take operators 10 hours to provide records to demonstrate that their pipeline cannot accommodate an inline inspection device for an overall annual burden of 100 hours for this notification requirement.

Affected Public: Owners and operators of hazardous liquid pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 110.

Total Annual Burden Hours: 125.

Frequency of Collection: Annually.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone (202) 366–4595.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Those desiring to comment on these information collections should send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to October 31, 2019. Comments may also be sent via email to the Office of Management and Budget at the following address: *oira_submissions@omb.eop.gov.* OMB is required to make a decision concerning the collection of information requirements contained in this final rule between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if received within 30 days of publication.

I. Privacy Act Statement

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477), or at *http://www.regulations.gov.*

J. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN contained in the heading of this document may be used to cross-reference this action with the Unified Agenda.

List of Subjects in 49 CFR Part 195

Incorporation by reference, Integrity management, Pipeline safety.

In consideration of the foregoing, PHMSA is amending 49 CFR part 195 as follows:

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 1. Revise the authority citation for part 195 to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. Amend § 195.1 by adding paragraph (a)(5) and revising paragraphs (b)(2) and (b)(4) to read as follows:

§ 195.1 Which pipelines are covered by this part?

(a) * * *

(5) For purposes of the reporting requirements in subpart B of this part, any gathering line not already covered under paragraphs (a)(1), (2), (3) or (4) of this section.

(b) * * *

(2) Except for the reporting requirements of subpart B of this part, see § 195.13, transportation of a hazardous liquid through a pipeline by gravity.

* * * * *

(4) Except for the reporting requirements of subpart B of this part, see § 195.15, transportation of petroleum through an onshore rural gathering line that does not meet the definition of a ''regulated rural gathering line'' as provided in § 195.11. This exception does not apply to gathering lines in the inlets of the Gulf of Mexico subject to § 195.413.

* * * * *

■ 3. Amend § 195.2 by revising the definition for ''*Hazardous liquid*'' to read as follows:

§ 195.2 Definitions.

* * * * *

Hazardous liquid means petroleum, petroleum products, anhydrous ammonia, and ethanol or other non-petroleum fuel, including biofuel, which is flammable, toxic, or would be harmful to the environment if released in significant quantities.

* * * * *

§ 195.3 [Amended]

■ 4. In § 195.3, amend paragraph (g)(3) by removing ''§ 195.591'' and adding ''§§ 195.120 and 195.591'' in its place.

■ 5. Add § 195.13 to subpart A to read as follows:

§ 195.13 What requirements apply to pipelines transporting hazardous liquids by gravity?

(a) *Scope.* Pipelines transporting hazardous liquids by gravity must comply with the reporting requirements of subpart B of this part.

(b) *Implementation period*—(1) *Annual reporting.* Comply with the annual reporting requirements in subpart B of this part by March 31, 2021.

(2) *Accident and safety-related reporting.* Comply with the accident and safety-related condition reporting requirements in subpart B of this part by January 1, 2021.

(c) *Exceptions.* (1) This section does not apply to the transportation of a hazardous liquid in a gravity line that meets the definition of a low-stress pipeline, travels no farther than 1 mile from a facility boundary, and does not cross any waterways used for commercial navigation.

(2) The reporting requirements in §§ 195.52, 195.61, and 195.65 do not apply to the transportation of a hazardous liquid in a gravity line.

(3) The drug and alcohol testing requirements in part 199 of this subchapter do not apply to the transportation of a hazardous liquid in a gravity line.

■ 6. Add § 195.15 to subpart A to read as follows:

§ 195.15 What requirements apply to reporting-regulated-only gathering lines?

(a) *Scope.* Gathering lines that do not otherwise meet the definition of a regulated rural gathering line in § 195.11 and any gathering line not already covered under § 195.1(a)(1), (2), (3) or (4) must comply with the reporting requirements of subpart B of this part.

(b) *Implementation period*—(1) *Annual reporting.* Operators must comply with the annual reporting requirements in subpart B of this part by March 31, 2021.

(2) *Accident and safety-related condition reporting.* Operators must comply with the accident and safety-related condition reporting requirements in subpart B of this part by January 1, 2021.

(c) *Exceptions.* (1) This section does not apply to those gathering lines that are otherwise excepted under § 195.1(b)(3), (7), (8), (9), or (10).

(2) The reporting requirements in §§ 195.52, 195.61, and 195.65 do not apply to the transportation of a hazardous liquid in a gathering line that is specified in paragraph (a) of this section.

(3) The drug and alcohol testing requirements in part 199 of this subchapter do not apply to the transportation of a hazardous liquid in a gathering line that is specified in paragraph (a) of this section.

■ 7. Add § 195.65 to subpart B to read as follows:

§ 195.65 Safety data sheets.

(a) Each owner or operator of a hazardous liquid pipeline facility, following an accident involving a pipeline facility that results in a hazardous liquid spill, must provide safety data sheets on any spilled hazardous liquid to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center.

(b) Definitions. In this section:

(1) *Federal On-Scene Coordinator.* The term ''Federal On-Scene Coordinator'' has the meaning given such term in section 311(a) of the Federal Water Pollution Control Act (33 U.S.C. 1321(a)).

(2) *National Response Center.* The term ''National Response Center'' means the center described under 40 CFR 300.125(a).

(3) *Safety data sheet.* The term ''safety data sheet'' means a safety data sheet required under 29 CFR 1910.1200.

■ 8. Revise § 195.120 to read as follows:

§ 195.120 Passage of internal inspection devices.

(a) *General.* Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each main line section of a pipeline where the line pipe, valve, fitting or other line component is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102 (incorporated by reference, *see* § 195.3).

(b) *Exceptions.* This section does not apply to:

(1) Manifolds;

(2) Station piping such as at pump stations, meter stations, or pressure reducing stations;

(3) Piping associated with tank farms and other storage facilities;

(4) Cross-overs;

(5) Pipe for which an instrumented internal inspection device is not commercially available; and

(6) Offshore pipelines, other than lines 10 inches (254 millimeters) or greater in nominal diameter, that transport liquids to onshore facilities.

(c) *Impracticability.* An operator may file a petition under § 190.9 for a finding that the requirements in paragraph (a) of this section should not be applied to a pipeline for reasons of impracticability.

(d) *Emergencies.* An operator need not comply with paragraph (a) of this section in constructing a new or replacement segment of a pipeline in an emergency. Within 30 days after discovering the emergency, the operator must file a petition under § 190.9 for a finding that requiring the design and construction of the new or replacement pipeline segment to accommodate passage of instrumented internal inspection devices would be impracticable as a result of the emergency. If PHMSA denies the petition, within 1 year after the date of the notice of the denial, the operator must modify the new or replacement pipeline segment to allow passage of instrumented internal inspection devices.

■ 9. Revise § 195.134 to read as follows:

§ 195.134 Leak detection.

(a) *Scope.* This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid).

(b) *General.* (1) For each pipeline constructed prior to October 1, 2019. Each pipeline must have a system for detecting leaks that complies with the requirements in § 195.444 by October 1, 2024.

(2) For each pipeline constructed on or after October 1, 2019. Each pipeline must have a system for detecting leaks that complies with the requirements in § 195.444 by October 1, 2020.

(c) *CPM leak detection systems.* A new computational pipeline monitoring (CPM) leak detection system or replaced component of an existing CPM system must be designed in accordance with the requirements in section 4.2 of API RP 1130 (incorporated by reference, see § 195.3) and any other applicable design criteria in that standard.

(d) *Exception.* The requirements of paragraph (b) of this section do not apply to offshore gathering or regulated rural gathering lines.

■ 10. In § 195.401, add paragraph (b)(3) to read as follows.

§ 195.401 General requirements.

* * * * *

(b) * * *

(3) *Prioritizing repairs.* An operator must consider the risk to people, property, and the environment in prioritizing the correction of any conditions referenced in paragraphs (b)(1) and (2) of this section.

* * * * *

■ 11. Add § 195.414 to read as follows:

§ 195.414 Inspections of pipelines in areas affected by extreme weather and natural disasters.

(a) *General.* Following an extreme weather event or natural disaster that has the likelihood of damage to infrastructure by the scouring or movement of the soil surrounding the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(b) *Inspection method.* An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under paragraph (a) of this section.

(c) *Time period.* The inspection required under paragraph (a) of this section must commence within 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 as determined under paragraph (b) of this section. In the event that the operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

(d) *Remedial action.* An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under paragraph (a) of this section. Such actions might include, but are not limited to:

(1) Reducing the operating pressure or shutting down the pipeline;

(2) Modifying, repairing, or replacing any damaged pipeline facilities;

(3) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(4) Performing additional patrols, surveys, tests, or inspections;

(5) Implementing emergency response activities with Federal, State, or local personnel; and

(6) Notifying affected communities of the steps that can be taken to ensure public safety.

■ 12. Add § 195.416 to read as follows:

§ 195.416 Pipeline assessments.

(a) *Scope.* This section applies to onshore line pipe that can accommodate inspection by means of in-line inspection tools and is not subject to the integrity management requirements in § 195.452.

(b) *General.* An operator must perform an initial assessment of each of its pipeline segments by October 1, 2029, and perform periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment.

(c) *Method.* Except as specified in paragraph (d) of this section, an operator must perform the integrity assessment for the range of relevant threats to the pipeline segment by the use of an appropriate in-line inspection tool(s). When performing an assessment using an in-line inspection tool, an operator must comply with § 195.591. An operator must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or other equivalent methods for determining uncertainties) in identifying anomalies. If this is impracticable based on operational limits, including operating pressure, low flow, and pipeline length or availability of in-line inspection tool technology for the pipe diameter, then the operator must perform the assessment using the appropriate method(s) in paragraphs (c)(1), (2), or (3) of this section for the range of relevant threats being assessed. The methods an operator selects to assess low-frequency electric resistance welded pipe, pipe with a seam factor less than 1.0 as defined in § 195.106(e) or lap-welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies. The following alternative assessment methods may be used as specified in this paragraph:

(1) A pressure test conducted in accordance with subpart E of this part;

(2) External corrosion direct assessment in accordance with § 195.588; or

(3) Other technology in accordance with paragraph (d).

(d) *Other technology.* Operators may elect to use other technologies if the operator can demonstrate the technology can provide an equivalent understanding of the condition of the line pipe for threat being assessed. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment by:

(1) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590; or

(2) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager by facsimile to (202) 366–7128.

(3) Prior to conducting the ''other technology'' assessments, the operator must receive a notice of ''no objection'' from the PHMSA Information Services Manager or Designee.

(e) *Data analysis.* A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. Operators must consider uncertainties in any reported results (including tool tolerance) as part of that analysis.

(f) *Discovery of condition.* For purposes of § 195.401(b)(1), discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination required under paragraph (e) of this section, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA and provide an expected date when adequate information will become available. This notification must be made in accordance with § 195.452 (m).

(g) *Remediation.* An operator must comply with the requirements in § 195.401 if a condition that could adversely affect the safe operation of a pipeline is discovered in complying with paragraphs (e) and (f) of this section.

(h) *Consideration of information.* An operator must consider all relevant information about a pipeline in complying with the requirements in paragraphs (a) through (g) of this section.

■ 13. Revise § 195.444 to read as follows:

§ 195.444 Leak detection.

(a) *Scope.* Except for offshore gathering and regulated rural gathering pipelines, this section applies to all hazardous liquid pipelines transporting liquid in single phase (without gas in the liquid).

(b) *General.* A pipeline must have an effective system for detecting leaks in accordance with §§ 195.134 or 195.452, as appropriate. An operator must evaluate the capability of its leak detection system to protect the public, property, and the environment and modify it as necessary to do so. At a minimum, an operator's evaluation must consider the following factors—length and size of the pipeline, type of product carried, the swiftness of leak detection, location of nearest response personnel, and leak history.

(c) *CPM leak detection systems.* Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline must comply with API RP 1130 (incorporated by reference, see § 195.3) in operating, maintaining, testing, record keeping, and dispatcher training of the system.

■ 14. Amend § 195.452 by:

■ a. Revising paragraphs (a)(3) and (b)(1), the introductory text of paragraph (c)(1)(i), paragraphs (c)(1)(i)(A), (d), (e)(1)(vii), and (g), the introductory text of paragraph (h)(1), and paragraph (h)(2);

■ b. Amending paragraph (i)(2)(viii) by removing the period at the end of the sentence and adding in its place a '';''.

■ c. Adding paragraph (i)(2)(ix);

■ d. Revising paragraph (j)(2);

■ e. Adding paragraphs (n) and (o).

The revisions and additions read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) * * *

(3) Category 3 includes pipelines constructed or converted after May 29, 2001, and low-stress pipelines in rural areas under § 195.12.

* * * * *

(b) * * *

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table no later than the date in the second column:

Pipeline	Date
Category 1	March 31, 2002.
Category 2	February 18, 2003.
Category 3	Date the pipeline begins operation or as provided in § 195.12 for low stress pipelines in rural areas.

* * * * *

(c) * * *

(1) * * *

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by in-line inspection tool(s) described in paragraph (c)(1)(i)(A) of this section for the range of relevant threats to the pipeline segment. If it is impracticable based upon the construction of the pipeline (*e.g.,* diameter changes, sharp bends, and elbows) or operational limits including operating pressure, low flow, pipeline length, or availability of in-line inspection tool technology for the pipe diameter, then the operator must use the appropriate method(s) in paragraphs (c)(1)(i)(B), (C), or (D) of this section for the range of relevant threats to the pipeline segment. The methods an operator selects to assess low-frequency electric resistance welded pipe, pipe with a seam factor less than 1.0 as defined in § 195.106(e) or lap-welded pipe susceptible to longitudinal seam failure, must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies.

(A) In-line inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges, and grooves. For pipeline segments with an identified or probable risk or threat related to cracks (such as at pipe body or weld seams) based on the risk factors specified in paragraph (e), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an in-line inspection tool, an operator must comply with § 195.591. An operator using this method must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or equivalent for determining uncertainties) in identifying anomalies;

* * * * *

(d) *When must operators complete baseline assessments?*

(1) *All pipelines.* An operator must complete the baseline assessment before a new or conversion-to-service pipeline

begins operation through the development of procedures, identification of high consequence areas, and pressure testing of could-affect high consequence areas in accordance with § 195.304.

(2) *Newly identified areas.* If an operator obtains information (whether from the information analysis required under paragraph (g) of this section, Census Bureau maps, or any other source) demonstrating that the area around a pipeline segment has changed to meet the definition of a high consequence area (*see* § 195.450), that area must be incorporated into the operator's baseline assessment plan within 1 year from the date that the information is obtained. An operator must complete the baseline assessment of any pipeline segment that could affect a newly identified high consequence area within 5 years from the date an operator identifies the area.

* * * * *

(e) * * *

(1) * * *

(vii) Local environmental factors that could affect the pipeline (*e.g.,* seismicity, corrosivity of soil, subsidence, climatic);

* * * * *

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (*see* paragraph (j) of this section), an operator must analyze all available information about the integrity of its entire pipeline and the consequences of a possible failure along the pipeline. Operators must continue to comply with the data integration elements specified in § 195.452(g) that were in effect on October 1, 2018, until October 1, 2022. Operators must begin to integrate all the data elements specified in this section starting October 1, 2020, with all attributes integrated by October 1, 2022. This analysis must:

(1) Integrate information and attributes about the pipeline that include, but are not limited to:

(i) Pipe diameter, wall thickness, grade, and seam type;

(ii) Pipe coating, including girth weld coating;

(iii) Maximum operating pressure (MOP) and temperature;

(iv) Endpoints of segments that could affect high consequence areas (HCAs);

(v) Hydrostatic test pressure including any test failures or leaks—if known;

(vi) Location of casings and if shorted;

(vii) Any in-service ruptures or leaks—including identified causes;

(viii) Data gathered through integrity assessments required under this section;

(ix) Close interval survey (CIS) survey results;

(x) Depth of cover surveys;

(xi) Corrosion protection (CP) rectifier readings;

(xii) CP test point survey readings and locations;

(xiii) AC/DC and foreign structure interference surveys;

(xiv) Pipe coating surveys and cathodic protection surveys.

(xv) Results of examinations of exposed portions of buried pipelines (*i.e.,* pipe and pipe coating condition, see § 195.569);

(xvi) Stress corrosion cracking (SCC) and other cracking (pipe body or weld) excavations and findings, including in-situ non-destructive examinations and analysis results for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipeline;

(xvii) Aerial photography;

(xviii) Location of foreign line crossings;

(xix) Pipe exposures resulting from repairs and encroachments;

(xx) Seismicity of the area; and

(xxi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this part.

(2) Consider information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline;

(3) Consider how a potential failure would affect high consequence areas, such as location of a water intake.

(4) Identify spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings; evidence of pipeline damage where aerial photography shows evidence of encroachment). Storing the information in a geographic information system (GIS), alone, is not sufficient. An operator must analyze for interrelationships among the data.

(h) * * *

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity, as required by this part. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with all other applicable requirements in this part in remediating a condition. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe and timely manner and are made so as to prevent damage to persons, property, or the environment. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats.

* * * * *

(2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA in accordance with paragraph (m) of this section and provide an expected date when adequate information will become available.

* * * * *

(i) * * *

(2) * * *

(ix) Seismicity of the area.

* * * * *

(j) * * *

(2) *Verifying covered segments.* An operator must verify the risk factors used in identifying pipeline segments that could affect a high consequence area on at least an annual basis not to exceed 15 months (Appendix C of this part provides additional guidance on factors that can influence whether a pipeline segment could affect a high consequence area). If a change in circumstance indicates that the prior consideration of a risk factor is no longer valid or that an operator should consider new risk factors, an operator must perform a new integrity analysis and evaluation to establish the endpoints of any previously identified covered segments. The integrity analysis and evaluation must include consideration of the results of any baseline and periodic integrity assessments (*see* paragraphs (b), (c), (d), and (e) of this section), information analyses (*see* paragraph (g) of this section), and decisions about remediation and preventive and mitigative actions (*see* paragraphs (h) and (i) of this section). An operator must complete the first annual verification

under this paragraph no later than July 1, 2021.

* * * * *

(n) *Accommodation of instrumented internal inspection devices*—

(1) *Scope.* This paragraph does not apply to any pipeline facilities listed in § 195.120(b).

(2) *General.* An operator must ensure that each pipeline is modified to accommodate the passage of an instrumented internal inspection device by July 2, 2040.

(3) *Newly identified areas.* If a pipeline could affect a newly identified high consequence area (*see* paragraph (d)(2) of this section) after July 2, 2035, an operator must modify the pipeline to accommodate the passage of an instrumented internal inspection device within 5 years of the date of identification or before performing the baseline assessment, whichever is sooner.

(4) *Lack of accommodation.* An operator may file a petition under § 190.9 of this chapter for a finding that the basic construction (*i.e.,* length, diameter, operating pressure, or location) of a pipeline cannot be modified to accommodate the passage of an instrumented internal inspection device or that the operator determines it would abandon or shut-down a pipeline as a result of the cost to comply with the requirement of this section.

(5) *Emergencies.* An operator may file a petition under § 190.9 of this chapter for a finding that a pipeline cannot be modified to accommodate the passage of an instrumented internal inspection device as a result of an emergency. An operator must file such a petition within 30 days after discovering the emergency. If the petition is denied, the operator must modify the pipeline to allow the passage of an instrumented internal inspection device within 1 year after the date of the notice of the denial.

■ 15. Add § 195.454 to Subpart F to read as follows:

§ 195.454 Integrity assessments for certain underwater hazardous liquid pipeline facilities located in high consequence areas.

Notwithstanding any pipeline integrity management program or integrity assessment schedule otherwise required under § 195.452, each operator of any underwater hazardous liquid pipeline facility located in a high consequence area that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water must ensure that:

(a) Pipeline integrity assessments using internal inspection technology appropriate for the integrity threats to the pipeline are completed not less often than once every 12 months, and;

(b) Pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, are completed on a schedule based on the risk that the pipeline facility poses to the high consequence area in which the pipeline facility is located.

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Howard R. Elliott,

Administrator.

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