DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2017–0151]

RIN 2137–AF29

Pipeline Safety: Class Location Change Requirements

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: In response to public input received as part of the rulemaking process, PHMSA is proposing to revise the Federal Pipeline Safety Regulations to amend the requirements for gas transmission pipeline segments that experience a change in class location. Under the existing regulations, pipeline segments located in areas where the population density has significantly increased must perform one of the following actions: Reduce the pressure of the pipeline segment, pressure test the pipeline segment to higher standards, or replace the pipeline segment. This proposed rule would add an alternative set of requirements operators could use, based on implementing integrity management principles and pipe eligibility criteria, to manage certain pipeline segments where the class location has changed from a Class 1 location to a Class 3 location. Through required periodic assessments, repair criteria, and other extra preventive and mitigative measures, PHMSA expects this alternative approach would provide long-term safety benefits consistent with the current natural gas pipeline safety rules while also providing cost savings for pipeline operators.

DATES: Persons interested in submitting written comments on this proposed rule must do so by December 14, 2020. Late-filed comments will be considered to the extent practicable.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2017–0151 by any of the following methods:

Federal eRulemaking Portal: https://www.regulations.gov. This site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the online instructions for submitting comments.

Mail: Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590–0001 between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays.

Fax: 1–202–493–2251.

Instructions: Identify the docket number PHMSA–2017–0151 at the beginning of your comments. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA has received your comments, include a self-addressed stamped postcard. Internet users may submit comments at *https://www.regulations.gov/.*

Note: Comments are posted without changes or edits to *https://www.regulations.gov,* including any personal information provided. There is a privacy statement published on *https://www.regulations.gov.*

Confidential Business Information

Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA) (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this notice contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this notice, it is important that you clearly designate the submitted comments as CBI. Pursuant to 49 CFR 190.343, you may ask PHMSA to give confidential treatment to information you give to the agency by taking the following steps: (1) Mark each page of the original document submission containing CBI as ''Confidential''; (2) send PHMSA, along with the original document, a second copy of the original document with the CBI deleted; and (3) explain why the information you are submitting is CBI. Unless you are notified otherwise, PHMSA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this notice. Submissions containing CBI should be sent to Robert Jagger, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, or by email at *robert.jagger@dot.gov.* Any commentary PHMSA receives that is not specifically designated as CBI will be placed in the public docket.

FOR FURTHER INFORMATION CONTACT: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361. For technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of Regulatory Action

Class locations are used in the natural gas Federal Pipeline Safety Regulations (PSR) in a graded approach to provide conservative safety margins [1] and safety standards commensurate with the potential consequences of pipeline

[1] Pipelines are designed with a safety margin between the design operating pressure and the pressure at which failure would occur. Safety margins are necessary because pipelines can be subject to emergency situations, unexpected loads, operator error, and material degradation.

incidents, and are based on the population density near a pipeline.[2] As class locations are defined with relation to the number of dwellings for human occupancy in the area, an onshore gas transmission pipeline's class location can change as the population living or working near a pipeline changes. An increase in population that results in a change in class location requires operators to confirm design factors and to recalculate the maximum allowable operating pressure (MAOP) of the pipeline.[3] If a class location changes and the hoop stress [4] corresponding to the established MAOP of a segment of pipeline is not commensurate with the MAOP of the newly determined class location, § 192.611 currently requires that the pipeline operator (1) lower the pipeline's MAOP to reduce stress levels in the pipe, (2) replace the existing pipe with pipe that has thicker walls or higher yield strength to yield a lower operating stress at the same MAOP, or (3) pressure test the pipeline at a higher test pressure.

Some operators have applied for special permits to manage class location changes that would normally require replacing pipe, reducing the operating pressure, or pressure testing the pipe. Under the special permit process, PHMSA waives or otherwise modifies compliance with regulatory requirements if the operator requesting the special permit demonstrates a need and PHMSA determines that granting the special permit would be consistent with pipeline safety.[5] PHMSA performs extensive technical analysis on special permit applications and has granted special permits on the condition that operators will perform alternative measures to retain a consistent level of pipeline safety for the new class location throughout the life cycle of the pipeline. In 2004, PHMSA published guidance in the **Federal Register** that addressed the common conditions for granting class location change special permit requests. This guidance clarified PHMSA's process for granting a class location waiver that would allow operators to perform alternative risk-control activities based on integrity management (IM) concepts, rather than pipe replacement, pressure testing, or pressure reductions.[6]

On January 3, 2012, Congress adopted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act).[7] Section 5 of that act required that PHMSA evaluate whether applying IM principles to areas outside of high consequence areas (HCA), with respect to gas transmission pipeline facilities, could possibly mitigate or eliminate the need for class location requirements.[8] As stated in the resulting class location report titled ''Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements'' that was issued in 2016 (2016 Class Location Report), the application of IM requirements to gas transmission pipelines outside of HCAs would not warrant the total elimination of class locations.[9] However, PHMSA stated that it intended to consider whether adjustments were needed in the way that operators were required to implement certain requirements when class locations did change.

On July 31, 2018, PHMSA published an advance notice of proposed rulemaking (ANPRM) in the **Federal Register** to seek feedback regarding the revision of the PSR applicable to the management of gas transmission pipeline segments where the class location has changed.[10] Specifically, PHMSA requested comments regarding whether operators should have the option of performing certain risk-based IM activities in lieu of the current required activities (*i.e.,* pipe replacement, pressure test, or pressure reduction) and whether those modifications could mitigate the public safety need for the existing class location requirements in this context. This ANPRM was initiated to honor the commitment made at the conclusion of the 2016 Class Location Report that PHMSA would study alternatives to the regulatory requirement for pipe replacement when class locations change and was also responsive to comments made to a 2017 DOT notice regarding regulatory review actions.[11]

Based on input in previous public meetings and workshops,[12] the comments received on the ANPRM, the 2016 Class Location report, and a review of PHMSA's active special permits for Class 1 to Class 3 location changes,[13] PHMSA proposes to amend the class location change regulations for certain in-service gas transmission segments where the class location has changed from a Class 1 to a Class 3 to add an IM-based alternative to the existing requirements. PHMSA is requesting input from the public on all aspects of this proposal, including whether the modification or elimination of the proposed pipe eligibility attributes or additional preventative and mitigative measures would provide an equivalent level of safety and maximize net benefits to society.

B. Summary of the Major Regulatory Provisions

PHMSA is proposing an IM-based alternative to the existing class-location-change requirements. The NPRM addresses two main topics pertaining to the IM alternative: (1) The criteria that pipe must meet to be eligible for the alternative, and (2) the additional, IM-based safety requirements necessary for using the alternative. Both aspects serve to protect public safety when pipeline operators apply the alternative approach.

[2] Class locations are defined at § 192.5. A ''class location unit'' is defined at § 192.5 as an onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. This distance is more colloquially known as the ''sliding mile'' and is explained in more detail later in this document. A Class 1 location is an offshore area or any class location unit with 10 or fewer buildings intended for human occupancy within the class location unit. A Class 2 location is any class location unit with more than 10 but fewer than 46 buildings intended for human occupancy within the class location unit. A Class 3 location is any class location unit with 46 or more buildings intended for human occupancy or an area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period within the class location unit, and a Class 4 location is any class location unit where buildings with 4 or more stories above ground are prevalent.

[3] Maximum allowable operating pressure is the maximum internal pressure at which a natural gas pipeline or pipeline segment may be operated.

[4] Hoop stress is stress that acts around the circumference of a pipe (*i.e.,* perpendicular to the pipe length) and is caused by the internal pressure pushing outward against the pipe wall. As pressure within the pipe increases, the stress in the pipe wall must be capable of acting against that pressure to contain it.

[5] The special permit process is outlined in § 190.341 and is no different for waiving the class location regulations than for waiving any other requirements in the PSR.

[6] Public notices were published in **Federal Register**: ''Pipeline Safety: Development of Class Location Change Waiver Guidelines,'' 69 FR 22115 (Apr. 23, 2004); and ''Pipeline Safety: Development of Class Location Change Waiver Criteria,'' 69 FR 38948 (June 29, 2004). Additional guidance is provided online at: *http://primis.phmsa.dot.gov/classloc/index.htm.*

[7] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011; signed January 3, 2012; Public Law 112–90.

[8] *Id.* at sec. 5(a).

[9] See *https://www.regulations.gov/document?D=PHMSA-2011-0023-0153.*

[10] ''Pipeline Safety: Class Location Change Requirements,'' 83 FR 36861 (July 31, 2018).

[11] ''Notification of Regulatory Review,'' 82 FR 45750 (Oct. 2, 2017).

[12] See Section II, D of this document titled, ''Class Location Studies, Public Workshop, Report, and Stakeholder Input.''

[13] As of May 1, 2019, PHMSA's 12 special permits for Class 1 to Class 3 location changes apply to segments of pipe in the States of Alabama, Arizona, Colorado, Georgia, Kentucky, Louisiana, Michigan, Mississippi, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Tennessee, Texas, West Virginia, and Wyoming.

The NPRM addresses segments that change from a Class 1 to a Class 3 location after the publication of a final rule based on this proposed rulemaking and operate at 72 percent of specified minimum yield strength (SMYS) [14] or less. PHMSA proposes that for segments that are eligible based on pipe attributes, operators choosing the IM alternative would adhere to documentation requirements, operations and maintenance (O&M) requirements, and other additional safety measures proposed in this rulemaking. Operators who do not meet the requirements of the proposed rule would need to follow the current regulatory requirements for class location changes or apply for a special permit.

Specifically, pipeline segments meeting the following conditions or having the following attributes would be ineligible for the IM alternative for managing class location changes:

- Bare pipe;
- Wrinkle bends;
- Missing material properties records;
- Certain historically problematic seam types; [15]
- Body, seam, or girth-weld cracking; [16]
- Pipe with poor external coating or with tape wraps or shrink sleeves;
- A leak or failure history within 5 miles of the segment; [17]
- Pipe transporting gas that is not of suitable composition and quality for sale to gas distribution customers; and
- Pipe operated in accordance with § 192.619 (c) or (d).

PHMSA also proposes that a pipeline segment would be ineligible if it did not have a documented successful [18] 8-hour, part 192, subpart J, pressure test to a minimum of 1.25 times MAOP. Pipeline segments that were previously ''uprated'' [19] without a documented pressure test would also not be eligible unless the operator conducts a new pressure test.

These applicability criteria would help protect public safety by assuring that pipeline segments with known elevated risks that are changing from a Class 1 to a Class 3 location are pressure-tested, de-rated to a lower MAOP, or replaced with new and stronger pipe, as required by the current regulations in § 192.611. In most cases, this eligibility criteria prevents pipe that would be more susceptible to corrosion or cracking from using this NPRM alternative, and it also helps to ensure that operators can use the proper assessment and mitigation methods on pipeline segments that could cause great harm to the public based on their risk. PHMSA is concerned that, with the additional risk for corrosion and cracking many of these segments would have, anomalies might be able to grow to a failure size before the next assessment. Therefore, PHMSA has proposed these eligibility criteria as a matter of ensuring that pipe integrity can be maintained in Class 3 locations where pipe designed to Class 1 standards remains in service. PHMSA discusses this in more detail later in this document and seeks comment on whether there is an alternative approach that would maximize net benefits to society while maintaining safety.

Pipeline segments changing to a Class 4 location would not be eligible for the IM alternative under this proposal, but would rather be accommodated through PHMSA's current class location special permit process.[20]

If a pipeline segment meets all eligibility criteria and the operator opts to follow the IM alternative, PHMSA proposes to require that the operator notify PHMSA of details of each segment that experienced a Class 1 to Class 3 location change 60 days prior to implementing the IM alternative.

PHMSA is also proposing to modify the definition of an HCA to include these Class 1 to Class 3 location segments, which would then make these specific segments subject to all the requirements in subpart O, in addition to the more stringent requirements discussed in more detail below. When subpart O was developed and promulgated in 2003,[21] PHMSA did not anticipate that operators would be able to demonstrate adequate pipeline integrity for pipe that was not designed for the class location in which it was located. Therefore, the regulations address any potential risk that would be involved when a class location changes by requiring that the pipeline operate at a lower pressure if an operator does not replace the pipeline segment or pressure test the segment. The proposal would allow operators to choose to follow IM requirements in subpart O and additional requirements for applicable segments, which include required in-line inspections (ILI), external pipeline coating, cathodic protection (CP),[22] pipeline repair criteria to maintain MAOP with a Class 1 location 39 percent safety factor, usage of remote-controlled or automatic shutoff valves, and other additional preventive and mitigative (P&M) measures. PHMSA expects these measures to provide for an equivalent level of safety for the life of the pipeline when compared to pipe replacement.

More specifically, PHMSA is proposing that operators perform an initial integrity assessment using ILI tools within 24 months of the class location change, which would align with the current timeframe to either confirm or change the MAOP after a class location change. PHMSA would require operators to perform this ILI assessment on the entire pipeline segment that has experienced the change in class location, including from the nearest upstream ILI tool launcher to the nearest downstream ILI tool receiver.

With respect to additional P&M measures beyond what are included in subpart O, PHMSA is proposing to require operators to do the following: Perform additional coating, interference, and corrosion surveys; remediate defined anomalies; install line-of-sight markers; install remote-control or automatic shutoff mainline valves; perform depth of cover surveys and

[14] SMYS is an indication of the minimum stress that a pipe may experience that will cause plastic, or permanent, deformation of the steel pipe.

[15] Problematic seam types include direct current (DC), low-frequency electric resistance welded pipe (LF–ERW), electric flash-welded (EFW) pipe, lap-welded pipe, and pipe seams with a longitudinal joint factor below 1.0 as defined in § 192.113.

[16] This cracking can include stress corrosion cracking and selective seam weld corrosion, which are cracking defects in the pipe body or weld seam. Cracks are undesired openings or separations in a normally rigid material, such as a pipe wall, and are detrimental to the capability of a pipeline to restrain pressure. Often, cracks are found only on the surface and do not penetrate the pipe wall. However, cracks that don't fully penetrate the pipe wall, if left unchecked, can propagate into a failure or a rupture and must be promptly repaired.

[17] These would be leaks or failures reported to PHMSA via an incident report per part 191.

[18] A ''successful'' pressure test is one where the pipe does not rupture or leak because of the test. Part 192, subpart J, prescribes the minimum leak-test and strength-test requirements for pipelines.

[19] An ''uprate'' is where an operator increases the MAOP of its pipeline. To increase the pressure on its pipeline, an operator must comply with the minimum requirements prescribed in subpart K of part 192. An operator would still be subject to the leak-test and strength test requirements, including recordkeeping requirements, under part 192, subpart J.

[20] PHMSA has neither included Class 4 locations in this proposed rule nor would it include such locations in any other NPRM without having first developed a unique set of conditions to maintain safety for multi-story buildings and applying them through the issuance of several special permits.

[21] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' 68 FR 69778 (Dec. 15, 2003).

[22] CP is a technique used to control or limit the corrosion of a pipeline's external metal surface by making it the cathode of an electrochemical cell. This treatment can be achieved with a special coating on the external surface of the pipeline along with an electrical system and anodes buried in the ground, or with a ''sacrificial'' or galvanic metal acting as an anode. In those types of systems, the anode will corrode before the protected metal will.

remediation; clear shorted casings; perform additional right-of-way patrols and leakage surveys; and use a supervisory control and data acquisition (SCADA) system. These additional requirements would address aspects of pipeline integrity and public safety for which ILI assessments alone do not address, such as reducing the likelihood of third-party damage, detecting and mitigating conditions that can accelerate corrosion growth, and terminating gas flow from ruptures faster than would be required under existing regulations.

Operators would also be required to keep documentation for all assessments, surveys, and any other required actions they perform in meeting the proposed requirements. PHMSA intends for this class location management option, when performed in conjunction with the requirements of subpart O, to provide a consistent-or-higher level of safety for the life of the pipeline if the operator chooses not to replace the pipe.

C. Costs and Benefits

Consistent with Executive Order 12866, PHMSA has prepared an assessment of the benefits and costs of this proposed rule, as well as reasonable alternatives. The estimated cost savings of this proposal are due to avoided pipe replacement of segments for which operators employ the proposed IM alternative. In the Preliminary Regulatory Impact Analysis (PRIA) posted on the public docket, PHMSA presented two estimates of the number of miles that may change from a Class 1 to a Class 3 location each year from 2019 to 2039 and analyzed them as two separate scenarios. Scenario 1 is based on an estimate of 78 miles per year, which is the average result from PHMSA's annual estimates based on historical annual report data from 2010 to 2017. Scenario 2 is based on the median of PHMSA's annual estimates, which is 118 miles. PHMSA estimated the cost savings of the proposed rule by estimating the rate and unit cost for the currently available class location change compliance methods, the unit costs of complying with the special permit program, and the mix of consequence classifications among the affected segments. PHMSA assumes that this proposed rule would cause operators to replace pipe less often when a class location changes from Class 1 to Class 3, as they would choose to use the IM alternative of this method where feasible. PHMSA estimated the costs of the IM alternative compared to the costs of pipe replacement against the estimated mileage changing from a Class 1 location to a Class 3 location per year. As such, PHMSA estimates the annual cost savings of the rule to be approximately $55 million for scenario 1, and $86 million for scenario 2, both calculated at a 7 percent discount rate.

II. Background

A. Class Location History and Purpose

The concept of class locations predates the Federal regulation of gas transmission pipelines and was an early method of differentiating areas along natural gas transmission pipelines based on the potential consequence of a hypothetical pipeline accident. The first class location definitions were incorporated into the PSR on August 19, 1970, and were derived from the American Society of Mechanical Engineers (ASME) B31.8 designations that were included in the American Standards Association B31.8–1968 version of the ''Gas Transmission and Distribution Pipeline Systems'' standard, which eventually became ASME B31.8, ''Gas Transmission and Distribution Pipeline Systems.'' The definitions for class locations that PHMSA codified maintained the original ASME B31.8 characterizations for Class 1 through Class 3 locations and added a new Class 4 location definition. These original class location definitions, with some slight modifications, are still applied today.

PHMSA uses class locations to provide safety margins and standards that are commensurate with the potential consequence of a pipeline failure based on the surrounding population. A pipeline's class location is based on the number of buildings or dwellings for human occupancy in the surrounding area.

Pipeline class locations for onshore gas pipelines are determined using the concept of a ''sliding mile,'' which is a unit of measurement that is 1 mile in length, extending 220 yards on either side of the centerline of a pipeline, and moves along the pipeline. The number of buildings within this sliding mile at any point during the mile's movement determines the class location for the entire mile of pipeline that the sliding mile moves along.[23]

A Class 1 location is a class location unit along a continuous mile containing 10 or fewer buildings intended for human occupancy or is an offshore area; a Class 2 location is a class location unit along a continuous mile containing 11 to 45 buildings intended for human occupancy; and a Class 3 location is a class location unit along a continuous mile containing 46 or more buildings intended for human occupancy, or is within 100 yards of a building or place of public assembly.[24] Class 4 locations exist where buildings with four or more stories above ground are prevalent. Whenever a pipeline segment has multiple class locations, the higher-numbered class location applies to the entire segment.

Potential consequences of personal injury and property damage resulting from incidents such as a leak- or rupture-type failure, increase in a more densely populated area. In addition, an increasing population around a pipeline amplifies the probability of an incident occurring due to additional external force stresses, corrosion, interference currents, loss of pipeline soil cover, damage from third parties, and other factors.

Design factors[25] are used along with pipe attributes in engineering calculations to determine the required design pressure and MAOP of each steel pipeline segment. To decrease operational hoop stresses[26] in areas of higher consequence, these class location-based design factors (*i.e.,* MAOP derating factors)[27] provide a safety margin and help ensure the pipeline is operated below 100 percent of SMYS. As specified in § 192.105, a pipeline's design pressure is determined using Barlow's Formula: $P = (2St/D) \times F \times E \times T$, where P is the design pressure, S is the pipe's yield strength, t is the wall thickness of the pipe, D is the outside diameter of the pipe, F is the design factor specific to the class location, E is the longitudinal joint factor,[28] and T is the temperature

[23] For the purposes of this rulemaking, a ''building'' may be interchangeably referred to as a ''home,'' a ''house,'' or a ''dwelling,'' all of which refer to a structure intended for human occupancy, whether it is used as a residence, for business, or for another purpose.

[24] Under § 192.5, a location is Class 3 if it has a building or a small, well-defined outside area (including playgrounds, recreation areas, and outdoor theaters) that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive.

[25] Design factors, which are used to calculate the design pressure for steel pipe in § 192.105(a), are listed in § 192.111. Class 1 locations have a 0.72 design factor, Class 2 locations have a 0.60 factor, Class 3 locations have a 0.50 factor, and Class 4 locations have a 0.40 design factor.

[26] ''Hoop stress'' is the stress in a pipe wall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe, that is produced by the pressure of the product in the pipe. Hoop stress is calculated using Barlow's Formula, which is at § 192.105. Hoop stresses are the same as design pressure, unless an outside force is acting on it. If hoop stress has the same safety factor as MAOP, then they are equal.

[27] MAOP determination and the required design factors for the class location can be found in §§ 192.105, 192.111, and 192.619.

[28] The longitudinal joint factor, based on the weld seam type of a pipeline, per this formula, has a

Continued

derating factor.[29] To illustrate how class location design factors influence the MAOP of a pipeline, consider a 1000 psig pipeline (1.0 design factor) with the same operating parameters (diameter, wall thickness, yield strength, seam type, and temperature) but in different class locations. The pipeline MAOPs would be as follows:

- Class 1—design factor = 0.72, MAOP = 720 psig
- Class 2—design factor = 0.60, MAOP = 600 psig
- Class 3—design factor = 0.50, MAOP = 500 psig
- Class 4—design factor = 0.40, MAOP = 400 psig

As natural gas transmission pipeline standards and regulations have evolved, the class location concept was incorporated into many other regulatory areas, including test pressures, mainline block valve spacing, pipeline design and construction requirements, and on-going O&M requirements. In all, the class location concept is incorporated throughout part 192.[30]

Modern pipeline inspection technology includes ILI and above-ground coating surveys. ILI technology uses devices that flow with the product in the pipeline and are colloquially known as ''smart pigs,'' which can measure and record irregularities in the pipe body and welds, including pipe wall loss (such as corrosion metal loss, gouges, scrapes, etc.), cracking, deformations, and dents.

There are various types of ILI tools using different technologies that have distinct capabilities for detecting specific types of pipeline anomalies. However, in selecting the most suitable ILI tool, a pipeline operator must know the type of threats that are applicable to the pipeline segment. For example, a high-resolution magnetic flux leakage (HR–MFL) ILI tool can detect internal and external corrosion metal loss reliably but cannot accurately determine whether the pipeline has dents, deformations, or tight crack indications such as stress corrosion cracking[31] or seam-weld cracks. A high-resolution deformation tool would be most appropriate for dents, whereas an electro-magnetic acoustic transducer (EMAT) tool would be the most appropriate for cracking.

PHMSA first issued its IM regulations for gas transmission pipelines on December 15, 2003,[32] in response to tragic gas pipeline incidents near Carlsbad, NM, in 2000,[33] where 12 people were killed; and in Edison, NJ, in 1994, where 8 buildings were destroyed and approximately 1,500 residents were evacuated.[34] The IM regulations provided a definition for HCA and required operators to assess the condition of pipelines periodically in these areas and make any necessary repairs within defined timeframes.

Prior to the recent publication of the ''Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments'' final rule on October 1, 2019 (2019 Gas Transmission Final Rule),[35] operators were not required to assess or perform IM functions on pipeline segments outside of HCAs. With the publication of that rule, operators of onshore steel transmission pipeline segments with an MAOP of greater than or equal to 30 percent of SMYS and that are located in a Class 3 locations, a Class 4 locations, or a ''moderate consequence area'' as defined in § 192.3 where the segment can accommodate inspection by means of an instrumented ILI tool, must assess their pipelines periodically, but on a less-frequent basis than those pipelines in HCAs.[36] The 2019 Gas Transmission Final Rule also requires operators to have a continuing surveillance program for all pipeline segments and take appropriate action to maintain safety concerning changes in class location, among other things.

B. Changes in Class Location Due to Population Growth

When the population around a pipeline increases and causes the class location to increase, the numeric value of the design factor decreases, which translates, as detailed in the formula in § 192.105, into a lower MAOP for the pipeline. As the dwellings within the class location unit grow such that a Class 1 location becomes a Class 3 location, the corresponding difference in design factor, from a 0.72 to 0.5, equates to an approximate 30 percent reduction in MAOP.

If a class location increases and the current MAOP is not commensurate with the MAOP for the newly determined class location, besides applying for a special permit, the existing regulations require that the operator:

(1) Reduce the pipeline's MAOP to reduce stress levels in the pipe;

(2) replace the existing pipe with pipe that has more wall thickness or higher yield strength to operate at a lower operating stress at the same MAOP; or

(3) conduct a pressure test (conforming to subpart J) at the higher test pressure needed to meet requirements for the newly determined class location if the pipeline segment has not previously been tested, for a minimum of 8 hours, at the higher pressure.[37]

In accordance with those options, depending on the pipeline's test pressure and whether it meets the requirements in §§ 192.609 and 192.611, the operator can base the pipeline's MAOP on a specified design factor multiplied by the test pressure for the new class location as long as the corresponding hoop stress does not exceed certain percentages of the SMYS of the pipe and as long as the pipeline has been tested for a period of 8 hours or longer per § 192.611(a)(1).[38] This

limiting effect on the MAOP of the pipeline. While it is typically ''1.00'' and would not affect the calculation, certain types of furnace butt-welded pipe or pipe not manufactured to certain 49 CFR part 192-approved industry standards will have factors of 0.60 or 0.80, which will necessitate a reduction in design pressure. The longitudinal joint factors for steel pipe are listed at § 192.113.

[29] The temperature derating factor ranges from 1.000 to 0.867 depending on the operating temperature of the pipeline. Pipelines designed to operate at 250 degrees Fahrenheit and lower have a factor of 1.000, which does not affect the design pressure calculation. Pipelines designed to operate at higher temperatures, including up to 450 degrees Fahrenheit, have derating factors less than one, which lowers the design pressure of the pipeline. Steel pipe temperature derating factors are listed at § 192.115.

[30] Specifically, §§ 192.5, 192.8, 192.9, 192.65, 192.105, 192.111, 192.150, 192.175, 192.179, 192.243, 192.327, 192.485, 192.503, 192.505, 192.609, 192.611, 192.613, 192.619, 192.620, 192.625, 192.705, 192.706, 192.707, 192.713, 192.903, 192.933, and 192.935.

[31] A ''tight crack'' is a crack that is below 0.008 inches in width. Stress corrosion cracking is a form of corrosion that produces a marked loss of pipeline strength with little metal loss. The combined influence of pipeline stress and a corrosive medium can result in the formation of interlinking crack clusters that can grow until the pipe fails.

[32] 68 FR at 69778.

[33] NTSB, Pipeline Accident Report: Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000, PAR–03–01, adopted on February 11, 2003.

[34] NTSB, Pipeline Accident Report: Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey; March 23, 1994; PAR–95–01, adopted on January 18, 1995.

[35] 84 FR 52180.

[36] 49 CFR 192.710.

[37] See § 192.611, as appropriate, for one-class changes (*e.g.,* Class 1 to 2 or Class 2 to 3 or Class 3 to 4). As an example, for a Class 1 to Class 2 location change, the pipeline segment would require a pressure test to 1.25 times the MAOP for at least 8 hours. Following a successful pressure test, the pipeline segment would not need to be replaced with new pipe, but the existing design factor of 0.72 for a Class 1 location would be acceptable for a Class 2 location. The pressure test must meet the documentation requirements of § 192.517.

[38] Specifically, if the applicable segment has been hydrostatically tested for a period of 8 hours or longer, the MAOP is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of SMYS of the pipe in

approach is practical for situations of a ''one-class bump'' where a pipeline segment's class location changes from Class 1 to a Class 2, a Class 2 to a Class 3, or a Class 3 to a Class 4.[39] However, when population growth occurs to a degree that results in a class location change from a Class 1 location to a Class 3 location, the existing options of pressure testing or reducing operating pressure can be technically or operationally prohibitive for meeting contractual gas flow volume obligations.[40] If an operator cannot pressure test or reduce operating pressure, the only options remaining per the existing regulations are to replace the pipe with higher-strength pipe by installing pipe with either greater wall thickness or higher steel grade or apply for a special permit.

The class location regulations, when they were promulgated in 1970, required operators to replace pipeline segments when population growth resulted in a class location change to ensure that the safety margin was commensurate with the new class location. At that time, the pipeline industry did not have the technology available to determine the in-situ [41] material condition of their pipelines, and it was unlikely that existing pipe could achieve a similar safety margin as replaced pipe per the regulations.

Following the implementation of the IM regulations in 2003, and throughout the development of the 2019 Gas Transmission Final Rule, pipeline operators and industry trade associations requested that PHMSA provide operators with an additional alternative to managing class location changes: One that would use modern IM principles to assess the pipelines in question and help ensure that their integrity is maintained. PHMSA is proposing and requesting comments on a defined IM alternative that operators can use to manage pipeline segments where the class location has changed from Class 1 to Class 3. PHMSA expects that the additional repair and monitoring criteria proposed in this rule would provide, for Class 1 pipe that is in a Class 3 location, safety for the life of the pipeline that would be equivalent to that provided by a pipeline designed to Class 3 standards. This NPRM would not allow operators to manage Class 1 to Class 4 or Class 2 to Class 4 location changes in the same manner. This restriction is because Class 4 locations are so densely populated that the measures that could be provided through an IM alternative on thinner-walled pipe designed for a Class 2 location would not give people a chance to evacuate from a nearby rupture. PHMSA does not believe, at this time, that there are additional, feasible measures that can be implemented, on top of the ones proposed in this NPRM for Class 1 to Class 3 location changes, that can mitigate such risk and stand in for thicker-walled or stronger, higher grade pipe designed to Class 4 standards. PHMSA seeks comment on this current understanding.

C. Class Location Change Special Permits

As discussed above, in the absence of alternative regulations such as those proposed in this notice, some operators have applied to PHMSA for special permits to manage class location changes without replacing pipe or reducing the operating pressure. A special permit is an order issued under § 190.341 that waives or modifies compliance with regulatory requirements if the pipeline operator can demonstrate a need, and PHMSA determines that granting the special permit or granting the special permit with conditions attached would be consistent with pipeline safety. Upon receipt of such a request, PHMSA publishes a notice and request for comment in the **Federal Register** for each special permit application received and tracks issued, denied, and expired special permits on its website.[42]

In 2004, PHMSA published the typical considerations for class location change special permit requests in a **Federal Register** notice titled ''Pipeline Safety: Development of Class Location Change Waiver Criteria'' (69 FR 38948; June 29, 2004; ''2004 **Federal Register** Notice''). These considerations were developed by adapting risk-based IM concepts. For each class location change special permit request, PHMSA reviews the information submitted by the operator, which includes a list of the proposed sites, pipeline attributes, prior assessment results and assessment schedules, incident and leak history, prior repairs, damage prevention initiatives, prior safety-related condition reports, a summary of integrity threats, and the operator's risk-control activities. PHMSA then approves class location change special permits on the condition that operators implement integrity assessments and other P&M measures, which go beyond the regulatory requirements.[43] The additional monitoring and maintenance requirements PHMSA prescribes through this process help to ensure the integrity of the pipe to maintain a level of safety consistent with lowering the MAOP, conducting a new pressure test, or installing thicker-walled or higher-grade pipe. The class location change special permits that PHMSA has granted have allowed operators to continue operating the pipeline segments identified under the special permits at their current MAOP based on the previous class locations. In order to issue such a special permit, PHMSA must determine that the present class location change special permit conditions and operator implementation of these conditions are consistent with public safety and demonstrate the current application of class location change management. As such, they can provide a basis for the consideration of this proposed alternative.

Since 2001, PHMSA has received over 30 applications from operators for waivers from the class location requirements in § 192.611 for pipeline segments changing from a Class 1 to a Class 3 location. PHMSA has approved approximately half of these applications and issued the corresponding special permits, with over 10 currently in effect.[44] The pipeline segments for

Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

[39] Based on the original in-place design of a pipeline, an operator can only perform a single one-class bump in a pipeline's lifetime. Pipelines constructed to the standards of lower class locations (*i.e.,* Class 1) cannot meet more rigorous testing requirements when class locations continue to increase, which eventually requires operators to replace the pipe or apply to PHMSA for a special permit.

[40] See the Preliminary Regulatory Impact Assessment (PRIA) for more details.

[41] In other words, the condition of their pipelines as they existed in place in the ground.

[42] *https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-and-state-waivers-overview.*

[43] Special permit conditions are implemented to mitigate the causes of gas transmission incidents and are based on the type of threats pertinent to the pipeline. The conditions are generally more heavily weighted on identifying material, coating, and CP issues; pipe wall loss; pipe and weld cracking; depth of pipe cover; third party damage prevention; marking of the pipeline and pipeline right-of-way patrols; pressure tests and documentation; data integration of integrity issues; and reassessment intervals. Examples of PHMSA's class location special permit conditions can be found at: *https://primis.phmsa.dot.gov/classloc/docs/SpecialPermit_ExampleClassLocSP_Conditions_090112_draft1.pdf,* and more information about PHMSA's special permit process for class location changes can be found at: *https://primis.phmsa.dot.gov/classloc/documents.htm.*

[44] PHMSA has rejected class location change special permits due to the presence of pipe conditions, including cracking, major corrosion, or other systemic issues, that are not easy to address via the special permit process. PHMSA considers the age and manufacturing process of the pipe and the construction processes used as well. Additionally, some operators have withdrawn special permit applications before being denied.

which PHMSA has granted special permits cover a range of diameters from 16 to 36 inches. Most the class location change special permits PHMSA has issued have been implemented effectively by operators and subsequently renewed; PHMSA notes that, to date, no leaks or failures have occurred on the approximately 100 miles of current class location change special permit pipeline segments.

i. Class Location Change Special Permit Eligibility Requirements

Most of the Class 1 to Class 3 class location change special permit requests that PHMSA receives are for older pipeline segments built with lower-strength pipe, based upon its design in accordance with 49 CFR 192.105 for a Class 1 location, that operators would likely not be able to pressure test to the 1.5 times MAOP test pressure without failure required for Class 3 locations.[45] Such pipe tends to be higher-risk due to the materials and construction techniques available at the time of the pipe's installation, so each pipeline segment must meet several ''threshold conditions'' before PHMSA grants a special permit. These conditions include a review of the pipe's seam type, field girth welds,[46] coating type, depth of cover,[47] materials documentation,[48] pressure testing duration and minimum test pressure,[49] defect and corrosion history, repair criteria used,[50] CP, and the quality of gas transported and its effect on internal corrosion.[51]

PHMSA also considers O&M practices and pipe attributes, and requires documentation when evaluating pipeline segment for a class location change special permit. For example, PHMSA does not grant class location special permits for pipeline segments with bare pipe or pipe containing wrinkle bends, or for pipe operating above 72 percent SMYS.[52] As a part of the special permit application process, operators must have or obtain documentation detailing the pipeline segment's diameter, wall thickness, grade, seam type, yield strength, tensile strength, and coating type. Finally, PHMSA considers the history of an operator's compliance with PSR when reviewing special permit applications.

ii. Special Permit Compliance Conditions

The conditions PHMSA imposes in class location change special permits apply to the ''special permit segment,'' which is the specific pipeline segment where the class location change has occurred. In class location change special permits, PHMSA has also required operators to assess for threats up to 25 miles on either side of the special permit segment in an area known as the ''special permit inspection area.''[53] The purpose of considering this larger special permit inspection area is to provide a means by which threats and pipe defects in nearby pipe can be discovered and remediated. In addition, potential incident causes that could affect the special permit segment can be identified and corrected, thus helping find and fix problems in the special permit segment before pipeline integrity is compromised.

PHMSA's typical class location change special permit conditions require an operator to incorporate the identified segment(s) into its integrity management program (IMP). An IMP, as detailed in subpart O of part 192, requires operators to perform ongoing risk analyses, perform integrity assessments to identify and analyze applicable threats to the pipeline, repair any anomalies, and implement appropriate P&M measures to ensure the integrity of the pipeline in HCAs (typically where there are significant populations). PHMSA's enforcement of operator IMPs holds operators accountable if they fail to take adequate steps under IM to mitigate the risks for their applicable pipeline segments.

Another condition included in class location change special permits is that each applicable special permit segment must be operated at or below its existing MAOP; this operating pressure is higher than the pressure reduction that would be required under the current class location change requirements in § 192.611. As a part of complying with the special permit conditions, and consistent with IM principles, PHMSA also requires operators to address issues pertaining to pipe coating quality, selective seam weld corrosion, stress corrosion cracking (SCC), and the effects of any long-term pipeline system flow reversals. In addition, PHMSA often requires operators to perform additional CP and corrosion-control measures on special permit segments, including performing coating condition surveys, coating remediation, and upgrading CP systems.

While PHMSA has the authority to modify special permit conditions in the interest of public safety, PHMSA has not significantly changed the original conditions imposed in the class location change special permits, in most cases, when operators apply to renew them. In a few cases in the early 2000s, class location SPs did not have required periodic reassessment intervals, pipe remediation, coating assessment, or other integrity requirements. PHMSA has added additional safety requirements when the special permits have been renewed. These early special permits were granted prior to the development of the class location change waiver guidelines and criteria in 2004. These public notices outlined the special permit attributes that PHMSA would review and gave an overview of the safety and integrity measures that PHMSA would require in future special permit conditions. In cases when certain changes have been made, they are a result of lessons learned during the special permit process. For example, when PHMSA first established the special permit process for class location changes in 2004, the special permits had no expiration dates. In 2008, the agency chose to impose an expiration date of 5 years for all new class location change special permits. At the time, PHMSA

[45] Some gas transmission infrastructure was installed before the 1970s, using techniques that can contain latent defects. For example, pipe manufactured using low-frequency electric resistance welding or lap-welding techniques is susceptible to seam failure.

[46] Girth welds are made where two pipes are joined along their circumferences. PHMSA reviews whether operators have performed non-destructive examinations of any girth welds and what percentage of the welds have been examined.

[47] The requirements for the depth of cover over a buried pipeline are at § 192.327, and they specify how much soil or consolidated rock must cover a pipeline at a given class location. PHMSA reviews whether there is less than 30 inches of cover over the pipeline and whether the pipe needs to be lowered or if additional mitigation measures need to be performed.

[48] PHMSA reviews whether the operator has good material physical property records of the pipeline segment and whether operators have documentation for wall thickness, seam types, etc.

[49] The pressure testing requirements for pipelines are in subpart J (§§ 192.501–192.517). PHMSA reviews whether operators have a proof test to confirm they have records for a safety factor above the MAOP (an increase of 25 percent).

[50] PHMSA reviews whether the repair criteria an operator uses has a required maximum defect depth and a pressure rating 39 percent above the MAOP.

[51] PHMSA reviews whether the gas has a high percentage of carbon dioxide (approximately 3 percent), or hydrogen sulfide (16 parts per million) and does not have water vapor above 7 lbs. per million. In PHMSA's experience, these thresholds are consistent with typical FERC gas tariffs for individual companies.

[52] Pipeline segments with these attributes do not meet the current part 192 standards for construction of transmission pipelines, regardless of the class location they are in. PHMSA approves special-permit applications based on the applicant's pipe being considered sound in accordance with current standards and ensuring through additional measures that an operator can manage the pipe to a consistent level of safety.

[53] In the class location change special permits, PHMSA required operators assess up to 25 miles on both sides of the special permit segment as a proxy for the nearest ILI tool launcher and receiver stations. As discussed later in this document, PHMSA is proposing to make explicit the requirement for operators to assess to ILI tool launcher and receiver stations in this NPRM.

felt that a 5-year expiration limit would serve as an appropriate frequency of review of the conditions and their impact on public safety. Based on PHMSA's experience over the past 15 years of monitoring these special permits and through safety reviews during the periodic special permit renewal process, PHMSA has extended the expiration date of its class location change special permits to 10 years. This 10-year timeframe allows an operator to conduct every required IM assessment and re-assessment [54] prior to submitting a renewal request to PHMSA for an updated special permit.[55]

D. Class Location Studies, Public Workshop, Report, and Stakeholder Input

Prior to this NPRM, PHMSA considered extensive input from various stakeholders on the class location change regulations, various other alternatives, and safety impacts. This feedback was gathered through the public comment process via a Notice of Inquiry in 2013,[56] public meetings in 2014, comments on the class location report and gas transmission NPRM in 2016, and comments to a DOT notice of regulatory review in 2017.[57]

i. Section 5 of the Pipeline Safety Act of 2011

On January 3, 2012, Congress enacted the 2011 Pipeline Safety Act. Section 5 of that act required PHMSA to evaluate, with respect to gas transmission pipeline facilities, whether the potential application of IM program requirements, or elements thereof, to additional areas outside of HCAs would mitigate the need for class location requirements. Per the mandate, PHMSA reported the findings of this evaluation to Congress in 2016, as discussed below. The 2011 Pipeline Safety Act authorized PHMSA to issue regulations pursuant to the findings of the report. As discussed below, PHMSA issued an NPRM in 2016 and a subsequent final rule in 2019 that addressed this mandate.

ii. 2013 Notice of Inquiry: Class Location Requirements

On August 1, 2013, PHMSA issued a Notice of Inquiry soliciting comments on whether expanding IM requirements would mitigate the need for class locations per the section 5 mandate of the 2011 Pipeline Safety Act. The notice discussed several topics, including whether class locations should be eliminated entirely, whether a single design factor could be used in all situations, whether design factors should be increased for higher class locations, and whether pipelines without complete material properties records should be allowed to use a single design factor if class locations were eliminated.

There was broad consensus among PHMSA stakeholders [58] that entirely eliminating class locations would not lead to pipeline safety improvement. Further, commenters noted that establishing a single design factor to replace class location designations might be too complicated to implement. Many commenters noted that any changes in class location requirements would impact not only the classifications of many pipelines but would also possibly lead to several adverse unintended consequences [59] related to compliance with 49 CFR part 192, as the class location requirements are referenced or built upon throughout the natural gas regulations. Several industry trade groups made suggestions for changing the class location regulations—specifically for using IM to manage pipeline segments where the operator had not replaced, pressure tested, or reduced the pressure of the pipeline segment. These suggestions were developed further through subsequent discussions at PHMSA's Gas Pipeline Advisory Committee (GPAC) meetings and at public workshops as described more fully below.

iii. 2014 Pipeline Advisory Committee Meeting, Class Location Workshop, and Subsequent Comments

On February 25, 2014, PHMSA hosted a joint meeting of the Gas and Liquid Pipeline Advisory Committees.[60] At that meeting, PHMSA updated the committees on its activities regarding section 5 of the 2011 Pipeline Safety Act, and committee members and participating members of the public provided their comments. During the meeting, the Interstate Natural Gas Association of America (INGAA) reinforced its comments in response to the 2013 Notice of Inquiry, noting that the original class location definitions in ASME B31.8 were intended to provide an increased margin of safety for higher-density population areas and stating that IM was a better risk-management tool than class locations. INGAA reported that its members intended to perform elements of IM on pipelines outside of HCAs.[61]

On April 16, 2014, PHMSA sponsored a workshop on class locations to solicit comments on whether the application of IM program requirements beyond HCAs would mitigate the need for gas pipeline class location requirements. Representatives from PHMSA, the National Energy Board of Canada, the National Association of Pipeline Safety Representatives (NAPSR), pipeline operators, industry groups, the Pipeline Safety Trust (PST), and public interest groups gave presentations.[62]

During the workshop, INGAA alleged that the current class location regulations can result in the replacement of pipeline segments that do not warrant replacement and suggested that the special permit process for class location changes be embedded into part 192. Ameren Illinois, a member of the American Gas Association (AGA), noted that applying the current class location change requirements can cost more than $1 million for each Class 1 to Class 3

[54] See 49 CFR 192.939.

[55] In all special permits, PHMSA reserves the right to revoke the permit (see § 190.341) before the set expiration date and order compliance with the regulations if PHMSA finds the operator is not complying with the provisions or if PHMSA discovers a safety condition on the pipeline.

[56] ''Pipeline Safety: Class Location Requirements,'' 78 FR 46560 (Aug. 1, 2013).

[57] ''Notification of Regulatory Review,'' 82 FR 45750 (Oct. 2, 2017).

[58] Approximately 30 submissions were received from a wide range of stakeholders, including, but not limited to: Operators, trade organizations (Interstate Natural Gas Association of America, American Public Gas Association, American Petroleum Institute, American Gas Association), the Pipeline Safety Trust public interest group, the National Association of Pipeline Safety Representatives comprised of State pipeline safety regulators, and individual citizens. The submissions can be reviewed at *https://www.regulations.gov/docket?D=PHMSA-2013-0161*.

[59] API/AEPC explained that the elimination of class locations would preclude the ability to determine the regulatory status of gathering lines. *See* API's November 1, 2013, comment at 3, *https://www.regulations.gov/document?D=PHMSA-2013-0161-0025*.

[60] The Pipeline Advisory Committees are statutorily mandated advisory committees that advise PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas and hazardous liquid pipelines (49 U.S.C. 60115). These Committees were established under the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. app. 2) and the Federal Pipeline Safety Statutes (49 U.S.C. 60101–60141, 60301–60302). Each committee consists of 15 members, with membership divided among Federal and State agency representatives, the regulated industry, and the public.

[61] Per a 2013 presentation, INGAA states that it will strive to apply IM principles to the entire transmission systems operated by INGAA members, extending and consistently applying the program to the following: (1) 90 percent of the population in the vicinity of pipelines using IM principles, by 2012; (2) 90 percent of the population in the vicinity of pipelines using ASME B31.8S, by 2020; (3) 100 percent of the population in the vicinity of nearby pipelines using IM principles, by 2030; and (4) the remaining 20 percent of pipeline mileage with no surrounding population using IM principles, after 2030. *https://www.ingaa.org/File.aspx?id=20899&v=a0233b08*.

[62] Meeting presentations are available online at: *http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=95*.

location change. Therefore, AGA suggested eliminating the special permit process for class location changes and incorporating the specific requirements for special permits into 49 CFR part 192 as part of the regulations. AGA recommended two alternative approaches. The first would allow operators to continue to implement the class location approach as it exists and apply for special permits, if needed. The second would allow operators to implement a risk-based approach using additional IM actions.

Accufacts and the PST pointed out how deeply the concept of class locations is embedded in part 192 and stated that IM requirements and class locations overlap in densely populated areas to provide a redundant, but necessary, safety regime. The PST also suggested that, in time, the older class location method potentially could be replaced with an IM method for regulation. However, the PST noted that incidents and other data suggest there is room for improvement in the IM regulations, as data shows higher incident rates in HCAs than in non-HCAs and that pipe installed after 2010 has a higher incident rate than pipe installed a decade earlier. Similarly, Accufacts noted that the 2010 Pacific Gas and Electric Company (PG&E) incident at San Bruno, CA, exposed weaknesses in the operator's IM program and demonstrated that the consequences resulting from the incident spread far beyond the expected potential impact radius (PIR).[63] Therefore, Accufacts suggested that shifting the class location approach solely to an IM approach might decrease the protection of public safety.

Following the workshop on class locations, INGAA submitted additional comments to the docket, stating that advancements in IM technology and processes have superseded the need for mandatory pipe replacement following a class location change. INGAA noted that in the past, it was logical to replace a pipeline when class locations changed because of the widespread belief that thicker pipe would take longer to corrode and would withstand greater external forces, such as damage from excavators, before failure. However, INGAA stated that given improvements in technology, advances in pipe quality, and ongoing regulatory processes such as IM, it believes that operators can mitigate most threats without the need for pipe replacement. Therefore, INGAA offered an approach to class location changes that would not require pipe replacement if pipeline segments met certain requirements that were in line with the current special permit conditions PHMSA established in the 2004 **Federal Register** Notice and that are currently in Class 1 to Class 3 location change special permits.[64] Specifically, INGAA suggested that pipelines meeting a ''fitness for service'' standard in 18 categories could address potential safety concerns and preclude the need for pipe replacement.[65]

iv. 2016 Class Location Report and Gas Transmission NPRM

Based on the 2011 congressional mandate discussed above, PHMSA submitted a report to Congress in April 2016 titled, ''Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements,'' which outlined PHMSA's findings on the issue.[66] The report also summarized operator comments and concerns regarding class location changes and subsequent pipe replacement, noting that operators said they could operate pipelines constructed in Class 1 locations that later change to Class 3 locations safely by using current IM practices.

Concurrently, PHMSA published an NPRM titled, ''Safety of Gas Transmission and Gathering Pipelines'' (2016 Gas Transmission NPRM),[67] in which PHMSA noted that the proposed application of IM program elements, such as assessment and remediation timeframes, beyond HCAs would not warrant the elimination of class locations.

In those documents, PHMSA noted that class locations affect all gas transmission pipelines and are integral to determining the appropriate MAOP, design pressure, pipe wall thickness, valve spacing, HCA designation,[68] O&M inspections, surveillance, and for evaluating anomalies for repair using ASME B31G[69] and AGA Pipeline Research Committee Project PR 3–805 (RSTRENG).[70] While IM measures are critical to risk mitigation and pipeline safety, the assessment and remediation of defects alone does not compensate for these other aspects of class locations adequately. Thus, as PHMSA outlined in the Class Location Report, it determined that the existing class location requirements are appropriate for maintaining pipeline safety and should be retained. Consequently, any revisions to the class location requirements would have to be forward-looking (*i.e.,* applying to pipelines constructed after a certain effective date) and would have to provide commensurate safety as the existing regulatory regime.[71]

As part of the continuing discussion on class location changes and subsequent pipe replacement, PHMSA summarized at the end of the 2016 Class Location Report the concerns operators expressed regarding the cost of replacing pipe in locations that change from a Class 1 to a Class 3 location or a Class 2 to a Class 4 location. PHMSA noted in the 2016 Class Location Report that, over the past decade, it had observed problems with pipe and fitting manufacturing quality, including low-

[63] The PIR for the ruptured pipeline segment involved in the PG&E incident at San Bruno, CA, was calculated at 414 feet. However, the National Transportation Safety Board (NTSB), in its accident report (NTSB/PAR–11/01) noted that the subsequent fire damage extended to a radius of about 600 feet from the blast center.

[64] See also *http://primis.phmsa.dot.gov/classloc/index.htm*.

[65] Those 18 categories were as follows: (1) Baseline Engineering and Record Assessments—Girth Weld Assessment, (2) Casing Assessment, (3) Pipe Seam Assessment, (4) Field Coating Assessment, (5) Cathodic Protection, (6) Interference Currents Control, (7) Close Interval Survey (CIS), (8) SCC Assessments, (9) In-line Inspection Assessments, (10) Metal Loss Anomaly Management, (11) Dent Anomaly Management, (12) Hard Spots Anomaly Management and Ongoing Requirements, (13) Integrity Management Program, (14) Root Cause Analysis for Failure or Leak, Line Markers, (15) Patrols, (16) Damage Prevention Best Practices, (17) Recordkeeping, and (18) Documentation.

[66] *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/55521/report-congress-evaluation-expanding-pipeline-imp-hcas-full.pdf*.

[67] ''Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines,'' 81 FR 20722 (Apr. 8, 2016).

[68] Per § 192.903, under Method 1, an HCA is an area defined as a Class 3 location, a Class 4 location, any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet and the area within the impact circle, which is defined by the potential impact radius for the pipeline, contains 20 or more buildings intended for human occupancy, or any area in a Class 1 or Class 2 location where the potential impact circle contains an ''identified site.''

[69] ASME B31G, ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' provides guidance for the evaluation of metal loss in pressurized pipelines and piping systems, and it applies to all pipelines and piping systems that are a part of the ASME B31 Code for Pressure Piping.

[70] For procedures to determine the remaining strength of pipelines, see §§ 192.485(c) and 192.933(d). RSTRENG is a computer program developed to perform the procedure called ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe.'' This procedure was developed by Battelle Memorial Institute for the American Gas Association as an alternative to the ASME B31G procedures.

[71] In comments following the public workshop on class locations in 2014, INGAA noted that, after further analysis, it appears that applying the PIR method to existing pipelines may be unworkable, which is detailed in: *https://www.regulations.gov/document?D=PHMSA-2013-0161-0037*.

strength material;[72] low-frequency and high-frequency electric resistance welded pipe seam quality; construction practices; welding and the non-destructive testing of welds; pipe denting; field coating practices; IM assessments and reassessment practices;[73] and record documentation practices.[74] Based on incidents resulting from these problems, PHMSA believes it is necessary to consider additional safety measures if allowing a ''two-class bump'' from a Class 1 location to a Class 3 location without requiring pipe replacement, especially for higher-pressure gas transmission pipelines.[75]

PHMSA stated in the conclusion of the 2016 Class Location Report that it would further evaluate the feasibility and the appropriateness of alternatives to address issues pertaining to pipe replacement requirements, continue to reach out to and consider input from all stakeholders, and consider future rulemaking if a cost-effective and safety-focused approach to adjusting specific aspects of class location requirements could be developed to address the issues raised by pipeline operators. In doing so, PHMSA noted it would evaluate class-location-change alternatives in the context of other issues it was addressing related to new construction quality and safety management systems and would also consider inspection findings, IM assessment results, and lessons learned from past incidents.

v. *The AGA/API/INGAA Submission on Regulatory Reform—Proposal To Perform Integrity Management Measures In Lieu of Pipe Replacement When Class Locations Change*

On October 2, 2017, DOT issued a Notification of Regulatory Review seeking comment from the public on existing rules and other agency actions that would be good candidates for repeal, replacement, suspension, or modification. On November 9, 2017, AGA, API, and INGAA submitted joint comments to the corresponding docket.[76] The joint comments asserted that gas transmission pipeline operators incur annual costs of $200 to $300 million nationwide replacing pipe solely to satisfy the class location change regulations. The joint commenters requested that PHMSA consider revising the current class location change regulations to include an alternative beyond pressure reduction, pressure testing, or pipe replacement, and provided a suggested approach for doing so.

The joint commenters proposed an alternative approach for class location changes that focused on operators performing ''recurring [IM] assessments . . . [that] leverage advanced assessment technologies to determine whether [the] actual pipe condition warrants replacement'' in areas where the class location has changed. The commenters stated that such an approach would further promote IM processes and principles throughout the Nation's gas transmission pipeline network, improve economic efficiency by reducing a regulatory burden, and help fulfill the purposes of section 5 of the 2011 Pipeline Safety Act.

The joint comments from AGA/API/INGAA asserted that the current alternatives to pipe replacement following a class location change do not reflect the substantial developments in IM processes, technologies, and regulations over the past 15 years since the initial IM regulations were first codified. The commenters suggested that advanced ILI technologies, such as HR–MFL tools, can assess the presence of corrosion and other potential defects, which can allow an operator to establish whether a pipeline segment needs remediation or replacement.

The joint comments further noted that the 2016 Gas Transmission NPRM would expand IM assessments to newly defined ''moderate consequence areas,''[77] and that such an expansion would provide a framework for developing an alternative means of managing class location changes. The commenters supported the publication of the proposed provisions, as endorsed by the GPAC, to help provide such a framework. They suggested that the costs saved from avoiding pipe replacement using such an alternative could mitigate, to some degree, part of the costs of the 2016 Gas Transmission NPRM. In addition, they noted that the gas transmission NPRM contained several new provisions that would require operators to manage the integrity of their pipelines better by implementing more P&M measures to manage the threat of corrosion. The joint comments from AGA/API/INGAA stated that including such corrosion control measures as a part of a program for managing the integrity of pipeline segments, including ones that have experienced class location changes, would further justify the development of an IM-focused alternative to class location changes.

Based on those statements, AGA, API, and INGAA recommended that PHMSA develop an alternative approach to § 192.611 that would leverage specific provisions in the 2016 Gas Transmission NPRM at its proposed § 192.710 for assessing areas outside of HCAs and apply the proposed IM requirements at § 192.921 to those assessed segments. Further, they suggested that operators could reconfirm a pipeline segment's MAOP in a changed class location if the pipeline segment in question did not have traceable, verifiable, and complete (TVC) records of a hydrostatic pressure test that supported the previous MAOP.

E. Class Location ANPRM

On July 31, 2018, PHMSA published an ANPRM in the **Federal Register** seeking public comment on its existing class location requirements for natural gas transmission pipelines as they pertain to the actions that operators are required to take following class location changes due to population growth near pipelines.[78]

In the ANPRM, PHMSA requested comments and information to determine whether revisions should be made to the PSR regarding the current requirements that operators must meet when class locations change. PHMSA also welcomed any additional information that would be beneficial to the rulemaking process.

[72] PHMSA has documented low-strength pipe material issues in an advisory bulletin and the following website link: *https://www.phmsa.dot.gov/pipeline/low-strength-pipe/low-strength-pipe-overview*.

[73] IM and operational procedures and practices were issues in PG&E's incident at San Bruno, CA, in September 2010 and the Enbridge hazardous liquid pipeline rupture near Marshall, MI, in July 2010. PHMSA issued Advisory Bulletins: ''Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation,'' ADB–11–01, 76 FR 1504 (Jan. 10, 2011) and ''Pipeline Safety: Using Meaningful Metrics in Conducting Integrity Management Program Evaluations,'' ADB–2012–10, 77 FR 72435 (Dec. 5, 2012) to operators regarding IM meaningful metrics and assessments, which can be reviewed at: *https://www.phmsa.dot.gov/regulations-fr/notices*.

[74] PHMSA issued Advisory Bulletin ''Pipeline Safety: Verification of Records,'' ADB–12–06, 77 FR 26822 (May 7, 2012) concerning the documentation of MAOP, which can be reviewed at: *https://www.phmsa.dot.gov/regulations-fr/notices*. Also note PHMSA's Advisory Bulletin ''Pipeline Safety: Deactivation of Threats,'' ADB–2017–01, 82 FR 14106 (Mar. 16, 2017).

[75] Section 192.611 allows a ''one-class bump'' based upon pressure test.

[76] PHMSA notes that INGAA, individually, submitted nearly identical comments on the topic of class location on July 24, 2017 in response to a previous request for input by DOT. ''Transportation Infrastructure: Notice of Review of Policy, Guidance, and Regulation,'' 82 FR 26734 (June 8, 2017).

[77] 81 FR at 20825, 20838.

[78] 83 FR 36861.

F. 2019 Gas Transmission Final Rule

Following the publication of the 2016 Gas Transmission NPRM, PHMSA determined it could more quickly move a rulemaking that focused on the mandates from the 2011 Pipeline Safety Act by splitting out the other provisions contained in the NPRM into two other, separate rules. Accordingly, on October 1, 2019, PHMSA published a final rule titled ''Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments.'' [79] PHMSA discusses the effects of that final rule on this proposal and any of the pertinent comments received on the ANPRM in the appropriate sections below.

III. Analysis of ANPRM Comments and PHMSA's Response

The deadline for submitting written comments on the ANPRM was October 1, 2018. PHMSA received comments from entities consisting of citizen groups; pipeline industry consulting groups; government agencies, including representatives from the State of New Jersey and an association of State pipeline regulators; pipeline operators; and pipeline industry trade associations. PHMSA also received comments from approximately 4,800 individuals. PHMSA has considered the feedback received to the ANPRM and has taken the information submitted into account in formulating this proposal.

The comments submitted by the approximately 4,800 individuals were similar to one another and urged PHMSA to keep the class change rules as they are now until PHMSA completes gas safety rules to ensure that operators have TVC records of their systems, as recommended by NTSB. Further, these commenters noted that the existing special permit application process and NEPA requirements ensure that there is a review of the characteristics of pipe being proposed to be left in the ground and that the public has notice of those times when an operator is seeking to be exempted from strength or testing regulations, and that the current rules provide operators options other than pipe replacement, while assuring that pipe that stays in the ground is of known strength and that the public is made aware of proposed exemptions.

The following subsections summarize the questions and proposals contained in the ANPRM, each of the relevant issues raised by the commenters, and PHMSA's responses to the comments.

[79] 84 FR 52180.

The comments, in their original form, and corresponding rulemaking materials can be viewed at *www.regulations.gov* under Docket ID: PHMSA–2017–0151.

A. Comments Related to the 2016 Proposed Gas Transmission Rule

PHMSA received several comments on the class location ANPRM regarding the gas transmission NPRM that was issued in April 2016 and how provisions within that proposed rule would relate to potential changes to the class location regulations. There was broad agreement and support across all PHMSA's stakeholders, from public interest groups to the industry trade associations, for finalizing the 2016 Gas Transmission NPRM [80] to implement important safety initiatives, provide regulatory certainty, and promote pipeline safety technology development. The PST, representatives from the State of New Jersey, and over 4,800 members of the public commented that any consideration of changes to the current class location regulations should be postponed until after the 2016 Gas Transmission NPRM went into effect to address critical safety issues that could influence this rulemaking.

In a combined submission, AGA, the American Public Gas Association (APGA), API, and INGAA (collectively, the ''Associations'') specified that any regulations regarding class locations should align with the 2016 Gas Transmission NPRM. This statement was supported by many pipeline operators. Members of the pipeline industry and the Associations commented that the repair requirements detailed in the 2016 Gas Transmission NPRM would be appropriate for managing the integrity of pipeline segments where the class location has changed.

1. PHMSA's Response to General Comments Related to the 2016 Proposed Gas Transmission Integrity Rule

PHMSA is managing the potential changes to the class location regulations in this NPRM independently and based on their own merits. PHMSA acknowledges that many of the technical requirements previously proposed in the 2016 Gas Transmission NPRM are pertinent and applicable to the issues surrounding class location changes. In some cases, provisions that were proposed in the 2016 Gas Transmission NPRM were finalized in the 2019 Gas Transmission Final Rule. Comments that pertain to any of the provisions of the Class Location ANPRM referencing proposed changes in the 2016 Gas Transmission NPRM are addressed in the specific topic areas below.

[80] The Final Rule based on this NPRM was published on October 1, 2019.

B. Requiring Pipe Integrity Upgrades and Allowing Other Options for Class Location Changes

1. Summary of ANPRM Questions 1, 1a, and 2

PHMSA requested comments on whether it should allow operators to upgrade the integrity of pipeline segments undergoing class location changes by using methods other than the existing methods of pressure reduction, pressure testing, pipe replacement, or special permits. For clarification, the ''pipe integrity upgrades'' referred to in the ANPRM are synonymous with the existing methods that operators must use (*i.e.,* pressure reduction, pressure test, or pipe replacement) to confirm or revise MAOP in accordance with § 192.611. PHMSA also asked whether it should require pipe integrity upgrades for areas where the class location has changed from a Class 1 to a Class 3 or from a Class 2 to a Class 4.

Similarly, in question 2, PHMSA asked whether it should provide operators with the option of performing certain IM measures, in lieu of the existing measures, when class locations change from Class 1 to Class 3.

2. Summary of Comments

The California Public Advocates Office commented that pipeline segments with adequate material properties records and a successful subpart J pressure test could be managed with the existing pipe integrity upgrades per § 192.611. It said that, in areas where the class location has changed and the pipeline segment is missing material properties records and does not have documentation of a successful subpart J pressure test, either those pipeline segments should be replaced or the operator should be required to apply for a special permit. Finally, it said that if a pipeline segment undergoing a class location change is missing records but does have documentation of a previous successful subpart J pressure test, that segment could be managed with a new pressure test, pipe replacement, or a special permit.

NAPSR and the PST remarked that the best way to ensure public safety is to continue to encourage pipe replacements and to allow PHMSA to issue special permits for class location changes. These commenters were skeptical that relying on operational practices, including IM, would be sufficient to ensure public safety, given that many accidents have been linked to operators mismanaging IM. These commenters also noted that the combination of prescribed design factors and IM better ensures safety through redundancy, and that this redundancy is good for public safety.

NAPSR and the PST also noted that, if IM concepts are used in lieu of pipe replacement, operators should be required to demonstrate improved safety levels through using IM program techniques or pressure test documentation.

Comments received from TransCanada Corporation (now TC Energy), Kinder Morgan, the Associations, GPA Midstream Association (GPA Midstream), and a member of the public expressed the view that PHMSA should allow operators to have the option of managing changes in class location with integrity assessments. The Associations stated that PHMSA should encourage operators to adopt IM measures, including those in the existing IM regulations and the regulations proposed in the 2016 Gas Transmission NPRM, to address threats posed by class location changes. In doing so, the Associations suggested, operators would gain knowledge about their systems that they would not have otherwise obtained. In addition, Enbridge noted that landowner disturbance and customer impact would be greatly reduced by reducing the amount of pipe replacements or hydrostatic tests conducted when class locations change.

Further, both Enbridge and the Associations suggested that PHMSA should allow operators to use integrity assessments as an MAOP confirmation (or revision) when class locations change, both from Class 1 to Class 3 and from Class 2 to Class 4. These commenters noted that pipeline technology has advanced since PHMSA promulgated the class location regulations. Commenters from the industry further stated that these technological advancements are feasible methods of ensuring operational integrity while managing class location changes. Therefore, operators and the Associations requested that PHMSA consider updating the class location regulations by allowing operators to perform aspects of IM when class locations change. These commenters suggested that operators would be able to analyze the condition of their pipelines through site-specific assessments and make sound pipe replacement determinations rather than follow prescriptive requirements.

Kinder Morgan added that regardless of the reason a class location changes, managing a class location change with IM principles is a more holistic approach than a ''one-time'' pipe replacement.

GPA Midstream suggested that PHMSA ''should not impose arbitrary restrictions on an operator's ability to address class location changes with appropriate operations, maintenance, and integrity measures,'' as operators can conduct risk assessments to determine the potential threats to a pipeline segment where the class location has changed. GPA Midstream further suggested that PHMSA's focus should be on making sure that operators complete such risk assessments within a reasonable amount of time and that appropriate documentation is maintained to substantiate compliance.

The Pennsylvania Grade Crude Oil Coalition (PGCOC), which represents small producers and refiners, stated that its members generally have limited resources compared with large pipeline operators. While the PGCOC supports an alternative to the current ways of managing class location changes, it requested that such an alternative not follow the framework of special permits. From its perspective, special permits contain numerous conditions that go beyond IM requirements and are unrelated to the change in class location. Furthermore, it suggested that the class-location regulations should provide certain exemptions or alternatives for small pipeline operators. Specifically, it suggested that PHMSA consider establishing minimal IM requirements for small operators.

An individual citizen noted that when comparing the failures in San Bruno, CA, and Carlsbad, NM, neither was associated with the operating stress of the pipeline. Rather, both incidents were caused by defects in the pipe itself and that these incidents were preventable using IM tools and methods. Further, this individual suggested that arbitrary pipe replacement when class locations change is not necessary, and these decisions should be made based on well-understood pipe conditions.

3. PHMSA Response

PHMSA agrees with many of the commenters that IM principles can serve as a useful and effective means of addressing the increased safety risks that accompany higher population densities near gas transmission pipelines. For this reason, in developing this proposed rule, PHMSA considered the ability of operators to demonstrate effectiveness and safety enhancements using IM performance metrics and methods. PHMSA also considered operators' recordkeeping practices and the documentation of previous pressure tests, as well as their ability to perform risk assessments. PHMSA's experience with class location change special permits demonstrates that IM methods can be appropriate for managing class location changes when implemented properly. Therefore, PHMSA is proposing to add an IM alternative to the existing class location change requirements for pipeline segments changing from a Class 1 to a Class 3 location.

On the other hand, the existing IM program is not a panacea for managing such risks. Class locations provide safety throughout the Nation's pipeline network by specifying stronger minimum safety standards for MAOP and design, construction, testing, and O&M requirements in higher class locations. The IM regulations provide a separate structure by which operators can focus their resources on managing and improving pipeline integrity in areas where a failure would have the greatest impact on public safety. Over time, pipelines can degrade due to integrity threats such as corrosion and cracking. IM provides minimum safety margins for more densely populated areas by requiring operators to assess their pipelines at a minimum of every 7 years, or more frequently, based on threat assessments or the predicted growth of anomalies found in HCAs.

For these reasons, this NPRM would not change the existing requirements for class location changes for pipelines that do not meet the proposed eligibility conditions but would instead provide an additional alternative for compliance. Newly constructed pipelines would still be required to be constructed based on part 192 class location requirements. Based on PHMSA's experience with class location special permits, as well as inspection results and incident history, the agency does not believe that IM, as it exists in subpart O, is suitable as the only appropriate method for class location change management. The IM regulations were crafted for pipe that was designed to a higher safety factor, and were not crafted for Class 1 pipe. Because the IM alternative proposed in this rule would allow operators to leave Class 1 pipe in the ground in locations where the population has increased to a Class 3 level, PHMSA is not confident that IM requirements, alone, would be adequate for protecting the population in those locations.

As a result, PHMSA is not proposing to allow pipe with higher-risk attributes to be eligible for the proposed IM alternative, including: Bare pipe; pipe with wrinkle bends; pipe with certain weld seams (*e.g.,* direct-current (DC), low-frequency electric resistance welded (LF–ERW), electric flash-welded (EFW), lap-welded seams, or seams where the longitudinal joint factor is below 1.0); and pipe with SCC, selective seam weld corrosion, or girth weld cracking (pipe body or weld cracking) corrosion. In addition, PHMSA is imposing additional mitigation requirements beyond those currently required under IM. Operators with higher-risk attribute pipe could continue to apply for special permits to manage class location changes.

PHMSA is also not proposing exceptions to the proposed IM alternative, as suggested by some commenters, because the existing options for class location change compliance and the special permit process would remain. Operators unable or unwilling to perform the IM alternative can achieve compliance through one of the existing options at § 192.611 or via a special permit.

PHMSA has not issued a special permit to manage locations changing from a Class 2 to a Class 4, because there is not an adequate basis for applying IM measures and concepts to these higher-risk pipeline segments. Though inspection technologies have advanced from earlier iterations, PHMSA does not have the operational data to confirm that the use of such technology on pipe designed to Class 2 standards would provide an adequate margin of safety in very densely populated Class 4 locations with multi-story buildings. PHMSA is concerned that there would not be adequate, feasible measures that could be prescribed to provide Class 4 locations with an equivalent level of safety in lieu of replacing pipe.

C. Integrity Upgrades and Integrity Management Options for Clustered Areas

1. Summary of ANPRM Questions 1b, 3, 3a, and 3b

In question 1b of the ANPRM, PHMSA asked whether part 192 should continue to require operators to upgrade pipeline integrity where the class location has changed from a Class 1 to a Class 3 due to the ''cluster rule.'' [81] In question 3, PHMSA asked whether the agency should give operators the option of performing certain IM measures in lieu of the existing measures when class locations change due to additional structures being built outside of an existing ''clustered'' areas within the sliding mile and operators are using the cluster adjustment to class locations per § 192.5(c)(2).[82] In sub-questions 3a and 3b, PHMSA asked whether, if alternative IM measures are permitted for pipelines, then what additional IM and maintenance measures should be applied to offset the safety impact of additional structures being built outside of clustered areas and at what intervals and in what timeframes operators should be required to assess these pipelines and perform remediation measures.

2. Summary of Comments

Multiple commenters expressed the view that options for actions taken in response to class location changes should not depend on whether clustering was used in determining the class location designation.

More specifically, the Associations strongly disagreed with PHMSA's statement in the ANPRM of a cluster being ''even a single house.'' They stated that in no prior class location rulemaking has the term ''cluster'' ever been defined. The Associations noted that in 1992, PHMSA, in response to an ANPRM question, specified that the word ''cluster'' was ''used in the ordinary dictionary sense,'' but, according to the Associations, the dictionary definition does not support the interpretation of one structure constituting a ''cluster.'' The Associations contended that the ordinary meaning of a cluster should continue to apply and each operator should be able to determine the scope of a cluster. Individual operator comments supported this view.

TransCanada Corporation suggested that PHMSA revise the ''cluster rule'' in § 192.5(c)(2) to cover only those situations where there are more than 10 buildings in close proximity, claiming that such a definition would be closer to the original intent of using class locations as a risk-mitigation tool and would be supported by a Class 1 location being defined as one with fewer than 10 buildings. Further, TransCanada noted that this proposed definition is supported by PHMSA's recent issuance of a class location special permit that distinguished between two differently sized clusters (*i.e.,* Type A and Type B), one with more and one with fewer than 10 buildings. Finally, it stated that categorizing low-population-density areas due to PHMSA's interpretation of the cluster rule as Class 3 locations artificially manipulates pipeline risk characterizations, in that small clusters of buildings (*e.g.,* 3) near larger clusters of buildings (*e.g.,* 50) would share the same risk profile. TransCanada stated that this approach results in outcomes that are inconsistent from the perspective of risk because a cluster with 50 buildings would have a higher activity rate, which would increase the likelihood of failure, and any failures would have higher consequences due to the denser population, whereas a cluster of 3 buildings would have less.

GPA Midstream also disagreed with assigning a single building as a defined cluster. It suggested that operators should determine the class location for the cluster specifically and determine the class location for the rest of the class location unit solely by considering the number of buildings outside of the clustered area. In this way, population density would drive class location determinations more accurately.

3. PHMSA Response

The ''cluster rule'' only applies when an operator has identified a class location unit that meets the criteria for a Class 2, Class 3, or Class 4 location. Once the Class 2, Class 3, or Class 4 location has been identified, the operator may adjust the endpoints of that Class 2, Class 3, or Class 4 location by using the cluster rule.[83] The purpose of this requirement is to allow operators to avoid replacing or pressure testing segments that have no buildings intended for human occupancy in the sliding mile and outside the ''cluster.''

PHMSA is not proposing any revisions to the clustering methodology in this NPRM. However, this proposed rule would address areas that might be affected by clustering by requiring that operators assess pipe with ILI tools and implement P&M measures for the entire segment.

D. Using an Integrity Management Option To Manage Safety When Class Locations Change From a Class 1 to a Class 3

1. Summary of ANPRM Question 2a

In question 2a of the ANPRM, PHMSA asked whether it should allow operators to use certain IM measures in

[81] See § 192.5(c)(2) and section I.B. of the ANPRM background for more details on the ''cluster rule.'' Operators can adjust the length of a Class 2, Class 3, or Class 4 location based on the presence of a ''cluster of buildings.'' Clustering reduces the amount of pipe that is subject to the safety requirements of higher class locations. Clustering does not change the length of the class location units themselves (*i.e.,* the ''sliding mile'').

[82] Under § 192.5(c)(2), the length of Class locations 2 and 3 may be adjusted as follows: When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

[83] See § 192.5(c).

lieu of the existing measures to ensure safety when class locations change from a Class 1 to a Class 3, and if so, what additional IM and maintenance approaches or safety measures should be applied to offset any potential impact to safety. PHMSA also asked at what intervals operators should be required to assess such pipelines and perform the necessary remediation measures.

2. Summary of Comments

NAPSR and the PST commented that specific design measures are more effective and consistently implemented than IM, as several recent failures have been attributed to IM implementation issues. Should PHMSA allow operators to use IM measures to manage class location changes, these commenters suggested that PHMSA should consider requiring more frequent integrity assessments, multiple tool type runs, more stringent repair requirements, and additional damage prevention activities.

Members of the pipeline industry recommended that PHMSA allow operators to use IM principles for managing class location changes, noting such an approach would allow operators to determine the threats associated with each pipeline segment and appropriate actions. Industry commenters also suggested that operators could implement the integrity assessment option for class location change management similarly to how it is implemented in subpart O, with at least one commenter noting that they could classify class location change segments as HCAs and manage the segments as a part of a broader IM program. Therefore, these commenters suggested that for both covered and non-covered segments that experience a class location change, operators could complete an initial assessment within 24 months of the class change, with reassessments to occur within 7 years or 10 years, depending on where the segment is located and the status of the 2016 Gas Transmission NPRM. Operators could complete the initial assessments using, at a minimum, ILI or comparable technology capable of assessing corrosion and dents. To ensure all identified threats would be addressed, operators could use additional assessment methods.

Certain industry commenters requested that PHMSA consider allowing operators to file for an extension if it is not practicable to complete an initial integrity assessment and MAOP reconfirmation, if required, within 24 months of a class change.

3. PHMSA Response

PHMSA agrees with NAPSR and the PST that if IM is used to manage class location changes, additional and enhanced requirements would be necessary to ensure pipeline safety. PHMSA also agrees that the timing of the initial integrity assessment should correspond with the current class location change requirement of 24 months. PHMSA is proposing reassessment intervals for the IM alternative of class location change management equivalent to the reassessment intervals in subpart O. As proposed in this NPRM, any segments managed through this IM alternative would need to be classified as HCAs, which are subject to subpart O; therefore, such a requirement would be consistent with the current regulations. Operators that do not identify the Class 1 to Class 3 location change in accordance with §§ 192.609 and 192.611(d) would not be able to use the class location change alternative proposed in this NPRM.

PHMSA agrees with commenters that IM is not suitable for class location change management in every situation. Under PHMSA's proposal, an operator would perform an analysis to identify those pipeline segments where the class location has changed, and identify those segments where it would be inappropriate to manage Class 1 to Class 3 location changes with IM. PHMSA notes that even if a pipeline segment meets the proposed minimum criteria discussed later in this NPRM, it does not mean that IM would be the best option for managing that pipeline segment. Based on their knowledge of their own pipeline systems, operators would ultimately determine whether an eligible pipeline segment should be managed with the IM alternative.

As a condition of using the IM alternative proposed in this rule, operators must notify PHMSA of their intent to use the alternative to allow PHMSA to review and inspect for compliance. PHMSA has learned through its inspections that many operators fail to assess and mitigate integrity problems properly, including poor construction practices [84] and operational maintenance threats, whether due to a lack of appropriate technologies, cost, or other reasons, threats that ultimately lead to pipeline failures. IM programs can fail to account for broadly recognized safety issues, such as bare pipe, wrinkle bends, lap welds, cracking, and pipe that has other potential construction or manufacturing issues. ILI technology does not effectively identify all integrity threats that may have been created through construction or manufacturing processes and that have not been tested for stability with a subpart J pressure test. Therefore, PHMSA believes such segments should not be managed using the IM alternative when class locations change.

Further, as the 2010 PG&E incident at San Bruno, CA, revealed, some operators may not have TVC records of certain pipe properties, such as pipe material yield strength, pipe wall thickness, pipe seam type, pipe and seam toughness, and coating type or quality. Data on these pipe properties are critical and necessary for the effective implementation of IM processes and pipeline safety measures in populated areas. PHMSA is concerned that operators may not have this pipe material property data for Class 1 pipe segments in locations that later become Class 3, especially if the pipe has been operated in accordance with § 192.619(c).[85] This data is necessary for making important pipeline safety judgments, including technical evaluations of anomalies.

PHMSA also notes that there may be instances where a pipeline appears to be in ''good condition'' from a visual standpoint, but may not have the initial pipe manufacturing, pipe body and seam strength, construction quality, coating, and CP effectiveness to prevent corrosion and cracking, and therefore lack the O&M history necessary for the effective management of class location changes using IM.

[84] On several occasions in recent years, PHMSA has met with operators to discuss safety issues related to new construction. For example, PHMSA hosted a public workshop in collaboration with its State partners, the Federal Energy Regulatory Commission (FERC), and Canada's National Energy Board in April 2009. The objective of the public workshop was to inform the public, alert the industry, review lessons learned from inspections, and improve new pipeline construction practices prior to the 2009 construction season. The following website contains information discussed at the workshop and provides a forum in which to share additional information about pipeline construction concerns: *https://primis.phmsa.dot.gov/construction/index.htm*.

[85] Pipeline segments operated in accordance with § 192.619(c) were installed prior to adoption of the PSR and likely do not meet § 192.619(a)(1), (2), or (4), or they operate above 72 percent of SMYS. These pipeline segments may not have pressure test or material properties records. Section 192.619(c) allows pipelines put into service before July 1, 1970, that were found to be in satisfactory condition, to be operated in Class 1 locations at the highest actual operating pressure they achieved during the 5 years preceding July 1, 1970, regardless of the level of hoop stress on the pipe. Pipelines in Class 1 locations that are designed and operated to part 192 standards are otherwise limited to a maximum operating hoop stress of 72 percent of SMYS.

Therefore, PHMSA proposes to exclude pipe with certain pipe attributes and O&M parameters from the proposed IM alternative of managing class locations. PHMSA is concerned that some operators have not adequately identified and mitigated these integrity threats at a consistent and reliable level. Excluding these segments from the proposed IM alternative would ensure a higher level of safety. Operators would still be allowed to apply for special permits to manage such pipeline segments, but PHMSA would be able to evaluate them, and the public would be able to comment on them, on a case-by-case basis. PHMSA requests comment as to whether these proposed pipe eligibility conditions could be modified or eliminated, and if so, what the impacts to safety and the environment would be as well as the net benefits of this proposed rule.

In addition, PHMSA's experience with operator IM programs indicates that some operators do not have an IMP in place that includes sufficiently robust P&M measures in HCAs to address the various risks posed by changes in class locations. Therefore, PHMSA concludes that, while applying modern IM assessments and processes can be an appropriate way to manage certain class location changes, the addition of specific prescriptive, additional P&M measures to such a method is needed to ensure a level of safety comparable to pipe replacement or derating the pipeline MAOP for pipeline segments that change from a Class 1 to Class 3 location. PHMSA requests comment as to whether modification or elimination of any of the proposed P&M measures, beyond the current IM requirements, is feasible and what the impacts to safety and the environment would be and whether such a change would maximize nets benefits to society.

Regarding the request that PHMSA allow operators to file for an extension to the 24-month assessment timeframe, PHMSA is not proposing to adopt that suggestion. PHMSA believes that 24 months is sufficient time to complete an initial IM assessment and that longer time frames would introduce undue risk to public safety by allowing Class 1 pipe to operate untested for more than 2 years in a Class 3 location. Currently, under § 192.611, if a class location change requires pipe replacement, MAOP reduction, or pressure tests to confirm a class location upgrade to be conducted, operators must complete those actions within 24 months of the class location change. PHMSA notes that the timeframe for this requirement was established at 24 months because it provides operators with enough time to order pipe, if necessary, and make changes from one season to the next. For example, if a class location change occurs in the spring, an operator would be able to order and receive pipe before replacing the pipe in the following summer season.

E. General Eligibility for Managing Class Location Changes With Integrity Management

1. Summary of ANPRM Questions 4, 4a, 4b, and 4c

In question 4 of the ANPRM, PHMSA requested comment on whether an operator should use a ''fitness-for-service'' [86] standard to determine which pipelines should be eligible for using IM measures to manage segments changing from a Class 1 to a Class 3 location, and what factors should make a pipeline eligible or ineligible for doing so.

PHMSA also asked whether it should base a proposed class location change management IM on the alternative criteria it uses when considering class location change waivers, including the pipe's age, the manufacturing and construction processes of the pipe, and the pipe's O&M history.

In addition, PHMSA asked whether it should require operators and pipelines to meet eligibility conditions outlined in the 2004 **Federal Register** Notice, including no bare pipe or pipe with wrinkle bends, records of a hydrostatic test to at least 1.25 times MAOP, records of ILI runs with no significant anomalies that would indicate systemic problems, and an agreement that up to 25 miles of pipe both upstream and downstream of the waiver location must be periodically inspected using ILI technology.

2. Summary of Comments

NAPSR and the PST stated that the existing § 192.609 serves as a fitness-for-service determination and suggested that operators should complete a fitness-for-service study for all pipeline segments, not just those impacted by a class location change. NAPSR and the PST further suggested that such a study should then be updated every 3 years, noting that the study results could assist in pipe replacement determinations when a class location change occurs. Pipeline industry commenters stated that a fitness-for-service standard should be established from the integrity assessments, enhanced repair criteria, and MAOP reconfirmation requirements proposed in the 2016 Gas Transmission NPRM. They stated that the initial MAOP establishment (or an MAOP reconfirmation where a pressure test record is not available) sets a physical safety margin that is then maintained for the life of the pipeline using integrity assessment, anomaly evaluation, and repair or replacement, where required based on pipe condition.

NAPSR, the PST, and the California Public Advocates Office commented that the criteria for class location change special permits that PHMSA published in the 2004 **Federal Register** Notice are all aspects of fitness-for-service, and PHMSA should use these factors as a basis for any proposed class location change requirements. Similarly, NAPSR and the PST commented that PHMSA should approve, on a case-by-case basis, an operator's request to utilize IM measures for class location changes taking into account a fitness-for-service study. The PST also said that PHMSA should not issue class location change special permits if the applicable pipeline segment cannot be assessed with ILI tools or does not have accurate and verifiable design records.

The Associations and supporting operators broadly commented that threshold conditions should not be required and that PHMSA should allow operators to use IM measures in lieu of pipeline replacement on all segments undergoing class location changes, stating that no individual pipe attribute should determine eligibility for a class location change alternative. Instead, these commenters suggested that PHMSA should encourage operators to utilize IM measures exclusively in lieu of the current requirements for managing these segments of pipelines where the class location has changed, including addressing threats as detailed in existing regulations and as proposed in the 2016 Gas Transmission NPRM. In doing so, these commenters argued, operators would gain knowledge about their systems that they would not have obtained otherwise.

Some operators, including TransCanada Corporation, proposed that operators should be allowed to conduct site-specific assessments to determine if pipeline segments should be eligible for using IM measures in lieu of pipe replacements or pressure reductions. Such an assessment would need to assess all applicable threats and their interactions to ensure that operators can manage safety at acceptable levels. An individual citizen noted that the acceptable current fitness-for-service standards are in ASME B31.8S, ASME B31G, RSTRENG, and their equivalents. This citizen further stated that

[86] ''Fitness for service'' refers to a pipeline's ability to operate and deliver product safely while protecting the people and environment around the pipeline. Fitness for service has been a part of industry consensus standards since the mid-1980s, and PHMSA has incorporated elements of these standards into the PSR.

reassessment is the key to assuring continued safety, and that lower stress does not assure public safety. The commenter further suggested that pipe segments should not be changed out if its condition is well understood and judged to be acceptable.

In addition, the Associations and supporting pipeline operators claimed that PHMSA's special permit requirement for assessing a prescribed amount of mileage upstream and downstream from the pipeline segment undergoing a class location change is not technically justified. They said that depending on the design of a pipeline system, such an assessment may require multiple tool runs or the analysis of pipe completely unrelated to the segment in which the class location has changed. Because PHMSA proposed to extend integrity assessments outside of HCAs in the 2016 Gas Transmission NPRM, these commenters suggested that special permit inspection areas are no longer appropriate or necessary to ensure pipeline safety. Similarly, Kinder Morgan stated that IM measures address segment threats, and the additional requirements detailed in the 2016 Gas Transmission NPRM will cover pipeline segments up and downstream of the class-location change.

An individual citizen commented that prescribing mileage to be assessed is not appropriate, as it could potentially exempt from the requirements pipeline segments that do not have 50 miles of pipe between ILI tool launcher and receivers.

Another individual citizen recommended that, if PHMSA were to allow an IM alternative for class location changes, operators should have to inform PHMSA and affiliated State agencies of their intent to apply IM measures for managing a pipeline segment changing from a Class 1 to a Class 3 location.

3. PHMSA Response

To the PST's comment that class location change special permits should not be issued if the applicable pipeline segment cannot be assessed with ILI tools or does not have accurate and verifiable design records, PHMSA is proposing to require in this NPRM that the segment must be ''piggable'' to be eligible for the IM alternative to the class location change requirements. Operators must also have pipe material property records for the segment to be eligible.

PHMSA does not believe that assessments and repairs alone are adequate to demonstrate the eligibility and fitness-for-service of pipe manufactured to Class 1 location standards to be used in Class 3 locations. In addition, PHMSA has elected to finalize the provisions proposed in the 2016 Gas Transmission NPRM in three separate final rules—the 2019 Gas Transmission Final Rule was published October 1, 2019, and the other two are in development. While the 2019 Gas Transmission Final Rule did include updated assessment requirements for ''moderate consequence areas,'' PHMSA intends to finalize the corresponding repair criteria in a draft final rule currently titled ''Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.'' PHMSA does not believe that managing Class 1 to Class 3 location changes using an updated assessment schedule with the existing repair criteria would provide an equivalent level of safety when compared to pipe replacement without additional P&M requirements being applied to the eligible pipe. ASME B31.8S allows anomalies to grow until only a 10 percent safety factor remains before they need to be remediated. In this NPRM, PHMSA is proposing that operators remediate anomalies that have a predicted failure pressure of less than 1.39 or a depth of less than 40 percent of the pipe wall thickness. This safety factor of 1.39 would be similar to the installation of new Class 1 pipe.

Further, PHMSA agrees with NAPSR and the PST that the study performed under the requirements at § 192.609, when a pipeline's class location changes is, in many ways, a type of fitness-for-service study. PHMSA is hesitant to incorporate a general requirement for operators to perform a fitness-for-service evaluation because PHMSA is concerned that such an evaluation would not result in a consistently applied minimum safety standard across the industry. Therefore, the specific eligibility conditions PHMSA is proposing in the IM alternative for threat identification in this NPRM would be akin to prescribing a fitness-for-service standard that operators would have to meet to use the IM alternative.

For the purposes of an operator determining if a segment would be ''fit for service'' to apply IM measures for managing pipeline segments changing from a Class 1 to a Class 3 location, PHMSA is proposing a set of pipe attributes that would disqualify a segment from using the IM alternative based on threats and their higher risks. Those attributes, and the corresponding threats, are:

(1) Bare pipe, which cannot maintain proper CP currents;

(2) Pipe with wrinkle bends, which can be prone to cracking;

(3) Pipe without records reflecting key attributes, including diameter, wall thickness, grade, seam type, yield strength, and tensile strength, which do not allow for proper anomaly evaluation;

(4) Pipe uprated in accordance with subpart K but without a pressure test to at least 1.39 times MAOP, unless the segment passes a subpart J pressure test for a minimum of 8 hours at a minimum pressure of 1.39 times MAOP within 24 months after the Class 1 to Class 3 location segment change and prior to uprating the MAOP. PHMSA believes that allowing pipe that has been operated for years at a lower pressure to be uprated without additional requirements presents undue risk;

(5) Pipe that has not been pressure tested in accordance with subpart J for 8 hours at a minimum test pressure of 1.25 times MAOP, unless the segment passes a subpart J pressure test for a minimum of 8 hours at a minimum pressure of 1.25 times MAOP within 24 months after the Class 1 to Class 3 segment change. The treatment of this attribute is consistent with the current regulatory requirements and will not allow pipeline segments that have been operating in accordance with § 192.619(c), which may lack material records or be operated above 72 percent SMYS, to be managed under the IM alternative;

(6) Pipe with DC, LF–ERW, EFW, or lap-welded seams, or with a longitudinal joint factor below 1.0, which are prone to seam failure due to cracking and improper jointing that results in lower-strength joints;

(7) Pipe, in or within 5 miles of the Class 1 to Class 3 location segment, with cracking in the pipe body, seam, or girth welds that is over 20 percent of the pipe wall thickness;[87] has a predicted failure pressure less than 100 percent of SMYS; has a predicted failure pressure less than 1.5 times MAOP;[88] has experienced a leak or rupture due to pipe cracking; or for which an analysis indicates the pipe could fail in brittle mode. Cracking leads to ruptures on pipe segments with poor toughness properties;

[87] In PHMSA's experience, current ILI tool detection effectiveness for cracks is at approximately 10 to 20 percent depth.

[88] This threshold is based on a related recommendation from the Gas Pipeline Advisory Committee on repair criteria. See *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132* for more details.

(8) Pipe with poor external coating that requires negative cathodic polarization voltage shifts of 100 millivolts or more,[89] or linear anodes to maintain cathodic protection, or pipe with tape wraps or shrink sleeves. The treatment of this attribute is consistent with Appendix D to part 192, which is referenced at § 192.463. Such pipe may have issues with corrosion control or cracking;

(9) Pipe transporting gas that is not of a suitable composition quality for sale to gas distribution customers, such as sour gas, which can lead to issues with corrosion; and

(10) Pipe that operates in accordance with § 192.619 (c) or (d).

Operators with such higher-risk pipeline segments would still be able to apply for a special permit for class location change management. Operators with pipeline segments that do not have any of the listed disqualifying attributes could use the IM alternative. PHMSA believes this proposed approach is a way to establish if Class 1 pipe is suitable (''fit for service'') for operators to use IM methods to verify MAOP in a Class 3 location, while providing an equivalent level of safety, over the life of a pipeline, as pipe replacement. As the majority of these disqualifying attributes have been used to ensure safety in class location special permits for several years, incorporating these disqualifying attributes into this rulemaking should provide an equivalent level of safety compared to the special permits. PHMSA requests comment as to whether these eligibility conditions are appropriate, and whether the elimination or modification of them would impact safety, and how. Is there an alternative approach PHMSA could take that would modify or eliminate these eligibility conditions that would maintain safety and increase the net benefits of this rulemaking?

PHMSA agrees with commenters that requiring operators to assess an additional 25 miles upstream and downstream from the class location change is unnecessary. When the general special permit conditions were drafted in 2004, PHMSA used the 25-mile inspection area as a sort of proxy for the length of pipeline between an ILI tool launcher and receiver. PHMSA is proposing to require instead that operators assess the length of pipeline between the ILI tool launcher and receiver containing the Class 1 to Class 3 location segment without prescribing a specific numeric value for the mileage to be assessed. The ILI tool launchers and receivers are the natural beginning and endpoints for an inspection area rather than an arbitrary amount of mileage.

PHMSA believes that approving each case in which an operator uses the proposed IM alternative for managing class location changes in lieu of pipe replacement is unnecessary for public safety and would not be significantly more efficient than the current approach of operators applying for special permits. However, PHMSA is proposing a notification requirement so that PHMSA and applicable State agencies are aware of each instance in which an operator uses the proposed IM alternative. This notification requirement will allow PHMSA and State regulators to know where these pipeline segments are located and can consider them when conducting inspections.

F. Eligibility for Pipe Operating in Accordance With § 192.619(c)

1. Summary of ANPRM Questions 1c and 4a(i)

In the ANPRM, PHMSA requested comments on whether pipe operating in accordance with § 192.619(c) (*e.g.,* pipeline segments with operating pressures above 72 percent SMYS, pipeline segments without a pressure test or with an inadequate pressure test, or pipeline segments with inadequate or missing material properties records), should be eligible for class location change management using IM principles. PHMSA also asked if part 192 should continue to require pipe integrity upgrades for pipeline segments operating in accordance with § 192.619(c).

2. Summary of Comments

NAPSR and the PST commented that pipeline segments operating in accordance with § 192.619(c) that lack design, material, or pressure test records should be required to follow the existing class location change requirements. They also seemed to suggest that, if PHMSA moved towards providing an IM alternative to class location changes, operators could incorporate pipeline segments operating in accordance with § 192.619(c) that have undergone a class location change into their IM programs if they performed more robust integrity assessments and mitigation measures on those segments.

The California Public Advocates Office requested that PHMSA confirm pipeline segments operating in accordance with § 192.619(c) will not be allowed to continue operating in accordance with § 192.619(c) after a class change, consistent with current regulations and interpretations. Specifically, they noted that PHMSA interpretation PI–14–0005 states:

> If an operator uses § 192.619(c) to establish the MAOP, the operator must have documentation of the pipeline segment's condition and operating and maintenance history, including historical pressure records for the maximum operating pressure to which the entire pipeline segment was subjected during the 5 years prior to July 1, 1970. Section 192.619(c) cannot be used to determine the MAOP after a change in Class Location. Section 192.611 can be used to revise the MAOP within 24 months after a Class Location change; after that deadline, the MAOP must be revised according to § 192.619(a).

The Associations and supporting operators recommended an IM alternative that would include hoop stress limitations as follows: 80 percent of the SMYS in Class 2 locations; 72 percent of SMYS in Class 3 locations; and 60 percent of SMYS in Class 4 locations. These commenters noted that a hoop stress limitation of 80 percent for Class 2 locations is supported by several existing special permits.

The Associations and supporting operators also noted that the 2016 Gas Transmission NPRM provides a means for reconfirmation of MAOP for pipeline segments operating in accordance with § 192.619(c).[90] So long as operators complete MAOP reconfirmation within 24 months of the class change, these commenters believed pipeline segments operating in accordance with § 192.619(c) should be eligible for the class location change alternative. However, these commenters also stated that the MAOP reconfirmation test factor used should correspond with the class location and installation date at the time of construction, claiming that if PHMSA enforced the use of current

[89] A.W. Peabody, ''Peabody's Control of Pipeline Corrosion,'' second edition, ''Criteria for Cathodic Protection.'' ''The 100 mV polarization criterion should not be used in areas subject to stray current because 100 mV of polarization may not be sufficient to mitigate corrosion in these areas. It is generally not possible to interrupt the source of the stray currents to accurately measure the depolarization. To apply this criterion, all DC current sources affecting the structure, including rectifiers, sacrificial anodes, and bonds must be interrupted. In many instances, this is not possible, especially on the older structures for which the criterion is most likely to be used. The 100 mV polarization criterion should not be used on structures that contain dissimilar metal couples because 100 mV of polarization may not be adequate to protect the active metal in the couple. This criterion also should not be used in areas where the intergranular form of external SCC, also referred to as high-pH or classical SCC is suspected. The potential range for cracking lies between the native potential and –850 mV (CSE) such that application of the 100 mV polarization criterion may place the potential of the structure in the range for cracking.''

[90] See 84 FR 52196 and 84 FR 52247.

class location test factors, it would likely result in pipe replacements or pressure reductions that undermine the application of IM principles due to the class location change segment not being designed to meet the Class 3 pressure test factors.

An individual citizen commented that the hoop stress of a pipeline segment cannot be determined if it has an unknown outside diameter, wall thickness, and SMYS. This commenter asked how an operator would be able to comply with class location change requirements if these values were unknown. If these variables were known, this commenter stated, then a multi-tool ILI inspection program in conjunction with chemical and physical sample tests would provide comparable assurance of compliance and safety.

3. PHMSA Response

Commenters are divided on whether pipeline segments operating in accordance with § 192.619(c) should be eligible for being managed with an IM alternative when class locations change. Pipeline segments operating in accordance with § 192.619(c) were installed prior to adoption of the PSR and that do not meet § 192.619(a)(1), (2), or (4), or they operate above 72 percent of SMYS. These pipeline segments may not have pressure test or material properties records.[91] Section 192.619(c) requires that an operator must still comply with § 192.611 should a class location change occur. This, in effect, precludes pipeline segments that operate in accordance with § 192.619(c) from continuing to operate without a pressure test or pressure reduction and records of pipe material properties when the class location changes. Given that pipeline segments operating in accordance with § 192.619(c) tend to be higher risk,[92] PHMSA's proposal states that pipeline segments operating at greater than 72 percent SMYS and pipeline segments that are missing pipe material properties records are not candidates for the proposed IM alternative to class location change management.

However, in this NPRM, PHMSA proposes that operators of pipelines that were previously operating in accordance with § 192.619(c) that operate at or below 72 percent SMYS be eligible for the IM alternative only if the operator pressure tests any of those pipelines that do not have a record of a previous pressure test within 24 months after the class location change and have pipe material records for the segment. PHMSA proposes such a pressure test must meet current subpart J requirements for a new segment installed in a Class 2 location (the test pressure must be at least 1.25 times MAOP for 8 continuous hours). Operators would need to test such pipeline segments to Class 2 standards rather than Class 3 standards because testing Class 1 pipe to Class 3 standards would result in a rupture and would require the operator to replace the pipe. This approach is consistent with the special permit conditions PHMSA has imposed on pipelines previously operating in accordance with § 192.619(c).

PHMSA is also proposing that this pressure-testing approach would apply to pipeline segments uprated in accordance with subpart K, except the pressure test for uprating the MAOP on a pipeline segment where the operator lowered the MAOP for a Class 1 to Class 3 location change would require a subpart J pressure test of 1.39 times the uprated MAOP for 8 continuous hours. Under this approach, operators would still be allowed to apply for a special permit for pipeline segments with the MAOP established in accordance with § 192.619(c) that would not meet the proposed requirements. Typically, an operator will downrate the pressure of a pipeline segment because the segment is not meeting regulatory standards and the contractual flow volumes have diminished (*i.e.,* they have lost customers). PHMSA is adding this requirement because if a pipeline is being uprated, it means that it has been operating at a lower pressure than to what the operator wants to raise the MAOP. Therefore, an operator must conduct a pressure test to a level that will justify the new, higher MAOP.

To the Associations' point regarding hoop stress limitations, class location change special permits have been limited to Class 1 to Class 3 location changes only. With the publication of the alternate MAOP rule in 2008,[93] PHMSA allowed pipelines to operate up to 80 percent SMYS in Class 1 locations if those pipelines were built to certain specifications and are operated with procedures that are additional (*e.g.,* 49 CFR 192.112, 192.328, and 192.620) to the normal procedures for pipelines operated at 72 percent SMYS. Pipelines built for Class 1 and Class 2 locations were not designed or constructed to operate at a hoop stress up to 80 percent SMYS. Should operators conclude that their design, construction, and operation procedures fulfill the standards of the Alternate MAOP rule at §§ 192.112, 192.328, and 192.620, then they can apply for a special permit in accordance with § 190.341.

G. Eligibility for Pipe With Specific Conditions and Attributes

1. Summary of ANPRM Questions 4a(ii), 4a(iii), 4a(vii), and 4a(viii)

In question 4 of the ANPRM, PHMSA requested comments on whether specific pipe conditions should affect a pipeline segment's eligibility for an IM alternative for class location management.

Specifically, PHMSA requested comments on whether pipeline segments that have a failure or leak history, were manufactured with a material or seam welding process during a time or by a manufacturer that has been shown over time to experience known integrity issues, or have lower toughness in the pipe and weld seam (*e.g.,* Charpy impact value[94]), should be eligible for an IM alternative. PHMSA also asked whether pipeline segments that contain or are susceptible to cracking, including in the body, seam, or girth weld, or pipeline segments that have disbonded coating or CP shielding coatings, should be eligible for the IM alternative. Further, PHMSA asked whether pipe with seams that are lap-welded, flash-welded, low-frequency electric resistance welded; are of ''unknown'' type; have a history of seam failure due to poor manufacturing properties; or have a derating factor below 1.0, should be eligible for an IM alternative.

2. Summary of Comments

The California Public Advocates Office stated that pipeline segments should not be eligible for the IM alternative for class location change management if they have experienced an in-service failure, have manufacturing issues, or have a lower toughness in the weld seam. It proposed that PHMSA consider holding a

[91] This data is included in PHMSA's annual reports. Pipeline operators are required to report which pipelines operate at greater than 72% SMYS, which method of MAOP determination was used for the pipeline, and whether the pipeline has incomplete records.

[92] Operators may know the material properties of pipeline segments operating in accordance with § 192.619(c). However, many pipeline segments operating in accordance with § 192.619(c) lack adequate material records, and may be operating at higher stress levels (above 72 percent SMYS) than what the pipe design would allow, if the pipe were to be constructed to today's standards.

[93] ''Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines,'' 73 FR 62148 (Oct. 17, 2008).

[94] A Charpy V-notch impact test and its values indicate the toughness of a given material at a specified temperature and is used in fracture mechanics analysis.

workshop to determine appropriate leak history thresholds and prescribe the eligibility of pipe with known integrity issues. It also commented that, if the operator does not know the seam type, the operator must determine the seam type or be required to use a longitudinal joint factor of 0.8 in any design calculations, even if the operator asserts all possible seam types merit a value of 1.0. It also expressed that, regardless of whether IM measures are deemed appropriate, the derating factor should be the more conservative of either the derating factor used at the time of construction or current design factors.

TransCanada Corporation commented that operators should conduct a site-specific assessment taking into consideration pipe design, history, and environmental factors to determine whether particular pipeline segments should be eligible for an IM alternative when class locations change. It argued that pipeline segments should be eligible if operators can use integrity measures to manage any associated threats effectively. It noted that lap-welded pipe was an exception and should not be eligible for IM measures, as current inspection technology is not sufficient in determining lap-weld seam integrity.

NAPSR and the PST expressed the view that PHMSA should consider all the factors listed in Question 4 of the ANPRM, including whether a pipeline is operating in accordance with § 192.619(c), has experienced an in-service failure, or has significant corrosion or other damage; the age of the pipe; manufacturing and construction history; O&M history; and the criteria listed in the 2004 **Federal Register** Notice for determining which pipeline segments would be eligible for operators to apply IM measures when managing class location changes in lieu of replacing pipe.

An individual citizen commented that pipe that has experienced an in-service failure should not be excluded so long as all comparable remaining defects in the segment have been remediated. This commenter suggested that pipeline segments with manufacturing defects should not be excluded from using an IM alternative when class locations change, so long as the operator has conducted a successful pressure test at 1.25 times the MAOP. Such a pressure test would demonstrate that the manufacturing defect should be considered stable and will not grow while the pipeline is in service. This commenter stated that while the Charpy impact value is shown to be related to crack growth, it is not a factor in corrosion and pressure stress cycles in gas pipelines are not a concern. This citizen also noted that, for unknown seam type, an ILI tool should be able to identify seam type given each seam type's distinct magnetic signature.

3. PHMSA Response

Based on the input provided and PHMSA's experience with special permits and incident investigations, PHMSA is persuaded that some of the attributes discussed, such as past incident history and toughness properties, can be effectively managed through an operator's IM program with mandatory P&M measures. In an operator's IM program, an operator addresses pipeline segments with an incident history through assessing and repairing or remediating the threats and causes associated with those past incidents. In this NPRM, PHMSA is proposing that operators would identify in their IM programs the specific Class 1 to Class 3 location segments being managed under that program. In doing so, operators would be required to conduct a data integration and risk assessment on these segments, including an evaluation of past incident history, for all threats and establish an integrity assessment program to find and remediate applicable threats.

This proposed rule specifies requirements for operators to maintain a comparable level of safety for the life of the pipeline segment that changed from a Class 1 to a Class 3 location. In response to the California Public Advocates Office's comment regarding derating factors, PHMSA believes that these requirements, including the IM principles and eligibility criteria prescribed in this NPRM, will provide the equivalent of conservative derating factors. PHMSA has issued several special permits over the past 15 years containing conditions identical to or similar to the conditions being proposed in this rulemaking for managing class location change waivers. Those special permits that PHMSA has issued have not resulted in any decrease in pipeline safety in the areas where they are implemented and in fact have resulted in no incidents on the applicable pipe. PHMSA, therefore, has confidence that the IM principles and eligibility criteria being proposed in this rulemaking will provide an equivalent level of safety consistent with the regulations.

PHMSA believes that pipeline segments with known cracking issues are problematic and is proposing that operators would not be allowed to use the IM alternative for class location change management for those pipeline segments with cracks that exceed 20 percent of wall thickness. PHMSA reached this threshold by considering the current state of ILI technology and its tolerance for finding crack indications; current ILI tools can consistently evaluate crack depth and length at this level. A 20 percent through-wall defect of the pipe, whether from cracking or corrosion, has a minimal effect on a pipeline's failure pressure ratio based on any of the approved defect analysis methods, such as R–STRENG or API 579. Operators of pipelines with cracking issues would continue to be eligible for class location change special permits.

Material toughness is important when evaluating cracks and crack-like defects, as cracking can weaken a pipe to the point where it might rupture.[95] Since PHMSA is proposing to exclude pipe with known, non-trivial cracking issues, PHMSA does not propose to include material toughness as an eligibility criterion for managing class location changes through IM. However, operators of pipeline segments that change from a Class 1 to a Class 3 location that identify cracking issues after implementing the proposed IM alternative for class location changes must evaluate the significance of those crack anomalies. PHMSA proposes to require crack evaluation procedures for that purpose. With respect to pipeline segments with unknown material toughness, the proposed crack evaluation procedures would require the operator to use conservative toughness values to evaluate predicted failure pressures in response to discovered crack anomalies and the threat of cracks. PHMSA proposes to define a ''predicted failure pressure'' as the calculated pipeline anomaly failure pressure based on the use of an appropriate engineering evaluation method for the type of anomaly being assessed. A predicted failure pressure does not include a safety factor, and PHMSA believes defining ''predicted failure pressure'' will help bring clarity to the regulations and improve compliance.

PHMSA also believes that operators of pipeline segments with certain seam attributes should not be allowed to manage class location changes with an IM alternative. Even the current and most state-of-the-art ILI technology, with respect to evaluating seams, is not yet reliable enough to warrant including such pipeline segments in this NPRM. PHMSA notes that, at this time, ILI tools cannot reliably identify or differentiate

[95] Material toughness is the ability of a material to absorb energy and plastically deform without fracturing. Technical evaluations, including anomaly evaluations, require material toughness as an input. If material toughness is low, then the safe pressure of the anomaly will also be low.

LF–ERW, HF–ERW, or lap-welded seam pipe. The pipeline would need to be excavated to observe pipe seam types and use appropriate destructive or non-destructive methods. Therefore, the proposed rule would not allow the use of the proposed IM alternative for pipeline segments with DC, LF–ERW, EFW, or lap-welded seams; or pipe with a longitudinal joint factor below 1.0.

H. Eligibility for Pipe With Significant Corrosion

1. Summary of ANPRM Questions 4a(iv) and 4a(v)

In question 4 of the ANPRM, PHMSA requested comments on whether operators should be eligible to use IM to manage class location changes if the pipeline segment has experienced corrosion greater than 40 percent of wall thickness,[96] or whether operators should replace such segments. PHMSA also requested comments regarding whether anomalies in pipeline segments in an IM-managed class location change segment should use similar repair criteria as subpart O, and whether the current class location-specific design factor was appropriate or if it should be increased for a Class 1 to a Class 3 location change.

2. Summary of Comments

The California Public Advocates Office commented that pipelines with significant corrosion should be replaced and should not be eligible for an IM alternative. It also suggested that PHMSA codify a definition of ''significant corrosion.''

The Associations, pipeline operators, and an individual commenter agreed that the current IM regulatory measures and those proposed in the 2016 Gas Transmission NPRM would identify ''significant corrosion'' through integrity assessments, and those areas would be remediated accordingly. In addition, the Associations noted that the GPAC and PHMSA discussed an appropriate response to wall loss anomalies during the March 2018 GPAC meeting.

Further, the Associations and supporting operators commented that 70 percent of corrosion incidents occurred on pipeline segments that were not previously assessed with ILI, which they suggested is evidence that the current industry practice to remediate corrosion anomalies based on ASME B31.8S for those lines that are assessed is an effective practice.

TransCanada Corporation proposed that anomalies, including corrosion anomalies, ''should be repaired to criteria greater than or equal to MAOP times the reciprocal of the design factor of the installed pipe.'' [97]

3. PHMSA Response

Based on the input provided and PHMSA's experience with special permits and incident investigations, PHMSA proposes to allow operators with pipe with past corrosion to use the IM alternative for Class 1 to Class 3 location changes. ILI technology for the detection of corrosion metal loss is very mature, and PHMSA believes it is reliable to manage the threat of corrosion in pipeline segments that have changed from a Class 1 to a Class 3 location if operators perform a corrosion assessment properly and validate the results. However, pipeline segments would not be eligible if they do not meet the requirements of § 192.463 and need linear anodes to maintain adequate levels of CP due to poor coating conditions.

To help ensure pipeline safety, PHMSA proposes enhanced repair criteria that would be performed in addition to the repair criteria for HCAs in subpart O and would be implemented if operators manage a Class 1 to Class 3 location segment through IM. This repair criteria would be consistent with the repair criteria per the typical class location change special permit conditions and includes immediate repair conditions [98] for certain anomalies that are at or near the point of failure. The repair criteria would also contain ''scheduled'' conditions that would require an operator to repair them within 1 year. These scheduled repairs would be for anomalies that are not an immediate threat to integrity but that would need to be repaired promptly before they grew further. PHMSA also proposes ''monitored'' conditions that are not severe enough to need prompt repair but that the operator would have to monitor further. The enhanced repair criteria would not only apply to the pipeline segment that has changed from a Class 1 to a Class 3 location, but would also apply to the surrounding Class 2, Class 3, and Class 4 locations contained within the in-line inspection segment (*i.e.,* the segment of pipe between the closest upstream launcher and downstream receiver that contains the Class 1 to Class 3 location segment). PHMSA believes that these enhanced repair criteria are necessary for pipe around the Class 1 to Class 3 segment because it is likely that there would be nearby populations that could be affected by an incident involving the in-line inspection segment. Regarding pipe segments with corrosion, implementing these enhanced repair criteria would manage pipeline segments with prior significant corrosion appropriately, which is needed to compensate for operators not installing new pipe to Class 3 design standards in the changed class location.

PHMSA is also proposing to exclude those pipeline segments that are not transporting distribution customer-quality gas from the IM alternative proposed in this rulemaking due to the impact contaminates have on corrosion. Such a proposal would prevent Class 1 to Class 3 location segments that transport gas with deleterious contaminates from being transported in segments near areas with higher populations. This criterion would also exclude pipeline segments transporting gas with free-flowing water or hydrocarbons, gas with higher levels of hydrogen sulfide (sour gas), gas with higher levels of carbon dioxide, or gas with unacceptable water content, specifically, as these segments would be at a higher risk of internal corrosion. Further, contaminants like hydrogen sulfide and carbon dioxide would be asphyxiation risks if a Class 1 to Class 3 location segment carrying significant percentages or volumes of these gases leaked or ruptured in a populated area.

Regarding TransCanada's comment, PHMSA is not proposing to require operators repair the reciprocal of the design factor of the pipe. PHMSA is proposing to require operators repair anomalies based on a 1.39 predicted failure pressure, which is the reciprocal of the 0.72 design factor for class 1 pipe, and a wall loss of 40 percent of the pipe wall thickness.

I. Eligibility for Damaged Pipe, Dented Pipe, or Pipe That Has Lost Ground Cover

1. Summary of ANPRM Question 4a(vi)

In question 4 of the ANPRM, PHMSA requested comments on whether operators should be eligible to use IM to manage class location changes if the pipeline segment has been damaged, dented, or has lost ground cover due to

[96] Corrosion greater than 40 percent of wall thickness is considered significant. This threshold is consistent with PHMSA's typical class location change special permit conditions.

[97] An example would be a pipeline segment in a Class 1 location with a § 192.111 design safety factor of 0.72. The reciprocal of 0.72 would be 1.39 (1/0.72), which is a safety factor of 39 percent over MAOP.

[98] Per ASME B31.8S, section 7.2, an ''immediate'' condition is one where an indication shows a defect is at a failure point. As such, PHMSA believes that any indication of a pipe that is at the point of failure needs to be addressed immediately. In addressing ''immediate'' conditions, operators must reduce operating pressure and immediately remediate the anomaly.

third-party excavation or environmental factors.

2. Summary of Comments

Regarding environmental factors, the Associations noted that operators are already required to conduct patrols with increasing frequency in Class 3 and Class 4 areas, and that the 2016 Gas Transmission NPRM, if finalized, will require operators to implement additional inspections following extreme weather events. Such events are the most likely cause of a sudden change in the depth of cover. The commenters suggested these existing and pending requirements are sufficient to monitor depth of cover changes to ensure pipeline safety, regardless of whether a class change has occurred.

An individual citizen commented that damaged pipe should be addressed as detailed in subpart O.

3. PHMSA Response

PHMSA does not propose to limit the eligibility of pipeline segments that have been damaged, dented, or have lost ground cover. ILI technology for the detection of dents is very mature, and PHMSA believes it is reliable to manage the threat of dents and mechanical damage in conjunction with the proposed additional repair criteria and existing dent repair criteria for HCAs in subpart O for pipeline segments where the class locations have changed from Class 1 to Class 3. PHMSA also added additional prescriptive P&M actions in the proposed provisions, including the addition of line markers or an increase in the depth of cover, to address cases where a pipeline segment that has changed class location from a Class 1 to a Class 3 location has experienced a reduction in the depth of cover.

J. Eligibility Factors Based on Diameter, Operating Pressure, or Potential Impact Radius Size

1. Summary of ANPRM Question 10

In question 10 of the ANPRM, PHMSA requested comments on whether operators should be eligible to use IM to manage class location changes based on the pipeline segment's diameter, operating pressure, or PIR size.

2. Summary of Comments

Pipeline industry operators and trade associations contended that applying diameter, pressure, or PIR limits are not necessary for determining the eligibility of pipeline segments for using IM principles in place of the existing class location requirements, specifically noting that there is currently no technical standard or regulation that limits an operator's decision-making based on the PIR size, and that the intent of the PIR concept was not to limit where integrity assessments could be applied.

GPA Midstream, in a comment that was echoed by other operators, stated that a ''one size fits all'' approach is not appropriate and suggested each operator should be allowed to determine the appropriate IM measures and actions to ensure safe asset management. It further suggested PHMSA should focus on ensuring operators appropriately apply IM measures.

NAPSR stated that any allowances or exceptions to the current regulations should be determined on a case-by-case basis. It suggested PHMSA should continue to encourage operators to operate pipelines at lower stresses, but operators that install pipe that is rated for a higher class location than what currently exists should not be punished.

The California Public Advocates Office suggested that PHMSA consider more conservative requirements for any IM-based class location change management based on the pipeline segment's PIR and that PHMSA should host a workshop to determine appropriate values or actions. It also suggested PHMSA consider looped, co-located pipelines as additional factors for any PIR-based adjustments.

An individual citizen noted that while diameter and pressure limitations are not necessary for pipeline segments where operators would use the IM alternative for managing class location changes, PHMSA should impose stricter repair criteria on those segments. The commenter also noted that immediate repair condition requirements are specified in the current regulations, and remediation requirements, if performed properly, for all areas, should provide safety beyond the next assessment.

3. PHMSA Response

PHMSA acknowledges that the PIR and class location concepts are both used to identify physical locations at which higher consequences could result from a pipeline incident by virtue of higher population density.[99] PHMSA believes that, for the purposes of managing class location changes, adding PIR-based exclusion criteria would be unnecessary. PHMSA believes the requirements it has proposed for pipeline segments where the class location has changed from a Class 1 to a Class 3 location are appropriate for all Class 3 locations regardless of the PIR at that location. Therefore, PHMSA is not proposing to limit eligibility or impose more stringent requirements based on pipe diameter, operating pressure, or PIR.

Furthermore, while PHMSA appreciates the feedback regarding changing the method for determining PIR and class location to include additional factors such as, looped, co-located pipelines, but this comment is outside the scope of this NPRM.

PHMSA considered the suggestion of more stringent repair criteria and included such criteria, in addition to the repair criteria in subpart O, for all Class 1 to Class 3 location segments operators would choose to manage with the IM alternative in this NPRM. The more stringent repair criteria that PHMSA proposes in this rule are designed to provide equivalent integrity compared to replacement pipe where a class location has changed from a Class 1 to a Class 3 location. Existing pipe in these locations is more likely than not to be pre-Code, vintage pipe where the steel pipe properties do not have the toughness properties necessary to mitigate ruptures versus leaks when the pipe is corroded, dented, or has any cracking in the pipe body or pipe seam.

K. Codifying Current Special Permit Conditions

1. Summary of ANPRM Questions 6 and 6a

In question 6 of the ANPRM, PHMSA requested comments on whether it should codify any or all the current special permit conditions for class location changes,[100] asking whether doing so would satisfy the need for alternative approaches. PHMSA also asked what special permit conditions could be codified to provide regulatory certainty and additional public safety in higher-population areas.

2. Summary of Comments

NAPSR and the PST commented that, if the current, typical special permit requirements are codified, they should be the minimum guidelines and should require multiple tool type assessments, an increased inspection frequency, more stringent remediation requirements, and enhanced damage prevention activities. They also recommended that PHMSA

[99] Per § 192.903, a PIR means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is used to determine whether an area is an HCA per the HCA definition at § 192.903. If, for the purposes of determining an HCA, a PIR in a certain class location is greater than 660 feet and the area within the potential impact circle contains 20 or more buildings intended for human occupancy or contain an identified site, as that term is defined at § 192.903, then the area is an HCA.

[100] Examples of typical PHMSA class location special permit conditions can be found at *https://primis.phmsa.dot.gov/classloc/documents.htm*.

require expedited timeframes and more restrictive remediation criteria specific to each class location.

The Associations, GPA Midstream, and operators commented that the current special permit conditions were not designed for broad application and should not be codified as written. The Associations stated that no additional requirements beyond those proposed in the 2016 Gas Transmission NPRM were necessary for operators to use IM to manage pipeline segments properly where the class location has changed. TransCanada Corporation added that implementing these ''broad-brush'' conditions would not allow for segment-specific risk considerations, which is the basis of an IM approach. GPA Midstream asserted that there are no indications the current special permit conditions would satisfy statutory considerations in a rulemaking proceeding, or that the cost of compliance is justified by the level of public safety benefit.

An individual citizen stated that certain aspects of current special permits are outdated given technological advancements and regulatory updates in the 14 years since the initial criteria for considering waivers was published. This citizen suggested that class location changes from a Class 1 to a Class 3 location should be treated as a change in land use, and the pipe in question should be considered an identified site, thus triggering HCA requirements.[101]

3. PHMSA Response

PHMSA agrees with certain commenters that including Class 1 to Class 3 location segments in operator IM programs in accordance with subpart O is appropriate for allowing operators to use IM to manage class location changes. However, PHMSA also believes that simply requiring operators to implement IM on pipeline segments where the class location has changed from a Class 1 to a Class 3 location, without undertaking additional safety requirements, does not provide an equivalent level of safety as the current system of pipe replacement, pressure testing, or pressure reduction. Thus, to provide public safety where the pipe has not been upgraded to current Class 3 location standards when the class location changes, PHMSA proposes to require that operators implement IM in accordance with subpart O and supplement that IM with additional standards that have been successfully applied in previous special permits. These additional activities would include close interval surveys (CIS),[102] the installation of CP test stations, and interference surveys to ensure the maintenance of coatings and reduce the numbers of immediate and scheduled repairs. These additional measures address specific threats to pipelines, including corrosion, and are necessary to account for the lack of additional pipe wall thickness in lieu of pipe replacement. Without thicker-walled pipe, these conditions will help to provide for a consistent level of safety over the lifecycle of the pipeline.

PHMSA is also proposing specific repair criteria for the Class 1 to Class 3 location segment that would be applied in addition to the existing repair criteria in subpart O. This additional repair criteria would also be applicable to the Class 2, Class 3, and Class 4 locations located within the entire in-line inspection segment. With these proposed changes, operators would categorize more anomalies as ''immediate'' conditions, which would help ensure an expedited repair schedule. Furthermore, the updated repair requirements of this proposal essentially provide an approximately 26 percent increase in safety factor for the pipe strength given that the NPRM would require the repair of conditions reaching a 1.39 safety ratio whereas the current IM regulations require the repair of conditions reaching a 1.1 safety ratio. The proposed repair criteria will also help to ensure safety where there is thinner-walled pipe in the ground by requiring the repair of anomalies where there is 40 percent of pipe wall loss, rather than the 80 percent that currently exists under IM.

Based on PHMSA's experience with existing Class 1 to Class 3 location change special permits and the feedback from the ANPRM, PHMSA proposes to incorporate the following special permit conditions into the regulations for those pipeline segments changing from a Class 1 to a Class 3 location that operators will manage using the IM alternative. PHMSA proposes to require the following conditions to help ensure that the level of safety achieved is equivalent to pipe replacement for the life of the pipeline:

- Perform an initial integrity assessment within 24 months of the Class 1 to Class 3 location change, which is consistent with the requirements at §§ 192.609 and 192.611.
- Use high-resolution ILI metal loss and deformation, electromagnetic acoustic transducer (EMAT), and inertial measurement unit (IMU) tools where appropriate for the pipeline integrity threat, which would be consistent with the current IM requirements. To help ensure that operators address cracking threats and ground movement, if an operator chooses not to conduct EMAT or IMU inspections on pipeline segments with a history of cracking or pipe movement, then the operator would be required to notify PHMSA in accordance with § 192.18.
- Perform periodic reassessments using ILI, which would be consistent with the current IM requirements.
- Validate ILI tool results, which would be consistent with the current IM requirements.
- Repair anomalies using more stringent repair criteria than the existing repair criteria under the current IM requirements, which will maintain equivalent safety, compared to pipe replacement, over the life of the pipeline.
- Replace pipeline segments: (1) With discovered cracks that exceed 20 percent of wall thickness, or (2) with a predicted failure pressure less than 100 percent of SMYS, or (3) with a predicted failure pressure less than 1.5 times MAOP, or (4) that could fail in the brittle failure mode. This requirement is based on PHMSA research and API's Recommended Practice 1176, ''Assessment and Management of Pipeline Cracking'' and would go beyond the current IM repair criteria.
- Until the pipeline segment can be replaced per the requirement above, cracks must be remediated using additional crack repair criteria. This requirement is consistent with the current IM requirements.
- Evaluate for pipe cracking, such as SCC, when the pipe is exposed for IM

[101] Under the current IM regulations at § 192.903, an ''identified site'' means ''one of the following 3 sites: (a) An outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period. The days need not be consecutive. Examples include, but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility. (b) A building that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4–H facilities, or roller skating rinks. (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include, but are not limited to, hospitals, prisons, schools, day-care facilities, retirement facilities, or assisted-living facilities.''

[102] CIS are a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized or native survey.

or the proposed regulation activities and is found with disbonded or previously repaired coating. Pipe excavated for damage prevention program activities under § 192.614 would not require pipe cracking inspections so as not to delay those activities. This treatment is consistent with the current IM requirements.

• Conduct close interval surveys (CIS) at intervals at least once every 7 years and not exceeding 90 months. Operators should be performing these surveys under the IM regulations, so this condition would be consistent with that requirement.

• Ensure that at least one CP pipe-to-soil test station is within the pipeline segment that changed from a Class 1 to a Class 3 location, with a maximum spacing interval of one-half mile. This condition will meet the current requirements at subpart I for corrosion control.

• Install line-of-sight markers at defined points, which is consistent with elements of the current requirement at § 192.707 and PHMSA's current special permit conditions for class location change management. Line-of-sight markers would be line markers where each marker is visible from at least one other line-of-sight marker.

• Conduct interference surveys, which would be consistent with the current requirements at § 192.473. If operators are unable to receive the necessary permitting authority to complete surveys in time, they can apply to PHMSA for a special permit regarding that issue.

• Maintain depth of cover to Class 1 location standards or remediate areas with reduced cover. This condition keeps the original design standards for the affected pipe segment so as to avoid imposing retroactive design standards, which PHMSA cannot do.

• Conduct right-of-way patrols on a monthly basis and leakage surveys on a quarterly basis. This condition will help to ensure, on a more consistent basis, that the pipe segment is not damaged by third-party entities and that hazardous leaks do not occur where there are substantial populations. These requirements will also provide safety in that they are more stringent than the current Class 3 requirements.

• Clear shorted casings within 1 year, which operators are already required to do in accordance with § 192.467.

• Document and maintain records, for the life of the pipeline, of the actions required by the Class 1 to Class 3 location requirements. This documentation requirement is consistent with requirements in the recently published 2019 Gas Transmission Final Rule.

PHMSA requests comment as to whether any of these P&M measures could be modified or otherwise eliminated, and if so, what the impacts of safety would be and if safety could be maintained, what alternative approach would maximize net benefits to society.

Per PHMSA's data over the last decade, there have been 699 ''significant'' incidents occurring on gas transmission pipelines, which are defined as ones involving (1) a fatality or in-patient hospitalization, (2) $50,000 or more in property damage, or (3) incidents where over 3 million cubic feet of gas are lost. Of these incidents, 269 were caused by material, equipment, or weld failures (38 percent); 165 by corrosion (24 percent); 93 by excavation damage (13 percent); 61 by natural force damage (9 percent); 42 by other outside force damage (6 percent); 40 by incorrect operation (6 percent); and 29 by other causes (4 percent).

In many ways, the conditions that are consistent with IM outlined above are meant to mitigate many of these incident causes, including material failure and corrosion. Performing recurring integrity assessments helps operators understand the current condition of their pipe and reveals anomalies that, if left unchecked, could result in a serious rupture and incident.

Some of the additional surveys PHMSA is proposing to require are additional safeguards against corrosion threats. In the absence of new, thicker-walled pipe in a Class 3 location, performing CIS and interference surveys, as well as ensuring the proper placement of CP test stations, will help to provide assurance that a pipeline segment will not rapidly corrode prior to being discovered before the next integrity assessment.

PHMSA is proposing conditions for line-of-sight markers and depth of cover because these serve as mitigation measures for potential accidents involving excavation damage. Excavation damage is more likely to happen in more populated areas, as there are typically more utilities near pipelines and more people digging around those utilities. A strike from excavation equipment can cause a rupture, severely dent the pipe, or damage the pipe's protective coating. Even though PHMSA is not proposing to require more stringent depth-of-cover conditions beyond those designed for Class 1 locations, PHMSA believes the additional line-of-sight markers combined with additional patrolling and leak survey requirements will provide a commensurate level of safety compared to the Class 3 depth of cover requirements.

PHMSA proposed including a condition for operators to clear shorted casings because shorted casings were major contributors in two major pipeline incidents. On December 14, 2007, a 30-inch gas transmission pipeline owned by Columbia Gulf Transmission Company ruptured near Delhi, LA, killing a man and injuring another man who were driving nearby on Interstate 20. On December 11, 2012, a 20-inch gas transmission pipeline operated by Columbia Gas Transmission Company ruptured about 100 feet west of Interstate 77 near Sissonville, WV. Three houses were destroyed by the fire, and several other houses were damaged. Interstate 77 was closed in both directions because of the fire and resulting damage to the road surface, causing delays to travelers and commercial freight. Both accidents were attributable to shorted casings that had not been properly addressed.

In addition to the above special permit conditions, PHMSA is also proposing to require operators use SCADA systems and install and use remote-control or automatic shutoff block valves upstream and downstream of the Class 1 to Class 3 segment. PHMSA believes that the additional P&M measures proposed in this NPRM, along with the higher standards for repairs and remediation, make an increased inspection frequency suggested by certain commenters unnecessary.

L. Additional Preventive and Mitigative Measures Needed for an Integrity Management Option for Class Location Change Management

1. Summary of ANPRM Questions 9, 9a, and 9b

In question 9 of the ANPRM, PHMSA requested comments on whether operators would need to install additional pipeline safety equipment, P&M measures, or more conservative prescribed standard pipeline predicted failure pressures if using IM principles to manage pipeline segments where the class location has changed from a Class 1 to a Class 3. More specifically, PHMSA requested comments on whether the regulations should require rupture-mitigation valves or SCADA systems on IM-managed class location change pipeline segments.

2. Summary of Comments

TransCanada Corporation proposed operators should perform site-specific assessments to determine the appropriate safety equipment or mitigative measures to implement. GPA Midstream supported this concept in its comments.

NAPSR stated that if PHMSA does not require pipe replacement, PHMSA should specify additional safety and P&M measures. They suggested that rupture-mitigation valves or equivalent technology should be required if an operator does not replace pipe to manage a class location change, and SCADA systems should be required for large and complex pipeline systems. Further, NAPSR stated that IM should be a system-wide program, ''not a substitute'' for the additional safety provided by class-location requirements. Similarly, NAPSR also stated that pipe replacements are preventive measures while valves are mitigative measures, arguing the level of safety between the two is not equal.

Broadly speaking, the Associations and multiple operators stated that the requirements proposed in the 2016 Gas Transmission NPRM are more than sufficient in ensuring safety, and it is unnecessary for PHMSA to require additional P&M measures for pipeline segments changing class locations. Class location change requirements, they asserted, are just a few of many regulations that are applicable to any given pipeline segment. MidAmerican Energy Company, for instance, stated that the requirements proposed in the 2016 Gas Transmission NPRM are adequate for covering class location changes, and no additional safety equipment or P&M measures should be required beyond those regulations.

Further, the Associations and GPA Midstream commented that the installation of rupture-mitigation values has not been addressed historically in special permits nor any previous class location regulatory discussions. GPA Midstream did not feel that this would achieve the intended purpose of class location change requirements, and PHMSA has not provided evidence or discussion in support of this requirement.

Similarly, the Associations commented that SCADA systems have not been required compliance items in special permits historically, and most gas transmission pipelines already have SCADA systems in place. They argued that this requirement seems unnecessary given that PHMSA has not provided evidence or discussion in support of this requirement.

GPA Midstream noted that, as currently allowed in the IM regulations, the operator should be able to determine the necessity of a SCADA system. It noted that for short pipelines or simple systems, it may be impractical. Other operators echoed this comment, noting that if a site-specific assessment determined that a SCADA system would be beneficial, the operator should have the option to add it.

Other operators provided a range of comments regarding SCADA systems, from supporting the viewpoint that impacted segments should be monitored with SCADA systems to general data indicating that large portions of their individual pipeline systems were managed with SCADA systems.

An individual citizen commented that the regulations currently do not require newly installed or previously installed pipe to have additional safety equipment or P&M measures. The commenter suggested that allowing operators to use ILI or similar technologies in a rigorous IM program would allow operators to know the pipeline segment's condition and remediate it appropriately, which would preclude the need for prescriptive P&M measures. In addition, this citizen commented that rupture-mitigation valves have limited efficacy and are not proven to be reliable technology. The commenter also noted that ''systems designed to react to ruptures will not be useful in detecting leaks.'' Further, the commenter noted that SCADA systems should not be required, as they only mitigate the consequences of an incident and will not prevent a rupture.

3. PHMSA Response

PHMSA has observed that certain operators have not adopted additional P&M measures when implementing the IM regulations under subpart O.[103] As a result, PHMSA has determined that proposing additional prescriptive mitigative measures are appropriate, including to install remote-control or automatic shutoff valves upstream and downstream of the segment changing from a Class 1 to a Class 3 location. While the installation of rupture-mitigation valves has not previously been required when operators replace pipe, using IM to manage class locations that change from Class 1 to Class 3 would be fundamentally different in that operators would not be putting stronger pipe in the ground, thereby making additional safety measures necessary.

As proposed, the rupture-mitigation valve spacing would be consistent with existing Class 1 location mainline valve spacing requirements, with the explicit intent that this approach would not require the addition of any mainline valves, and assuming operators currently comply with the existing valve spacing requirements. However, if the valves in place are manual valves, PHMSA proposes that operators upgrade those valves to be operated by remote control or automatic shutoff as an additional mitigative measure. This approach would be consistent with NTSB recommendation P–11–11 to require automatic or remote control valves in HCAs and Class 3 and Class 4 locations,[104] which was issued after the 2010 PG&E incident in San Bruno, CA.

PHMSA is proposing that any remote-control or automatic shutoff valves installed in accordance with the additional P&M measures must be set so that, based on operating conditions, they will fully close within a maximum of 30 minutes following rupture identification. PHMSA's proposed 30-minute valve closure time would be consistent with conditions it has required operators to meet in special permits for class location changes. In addition, PHMSA requests comment on whether additional requirements and standards are needed for the installation of automatic shutoff valves in place of remote-control valves for the purposes of this rulemaking. If installing automatic shutoff valves in accordance with this proposed requirement, operators would be required to review their procedures and results for determining valve shutoff times on a calendar year basis, not to exceed 15 months. This approach is consistent with current requirements in § 192.745 where operators must inspect and partially operate each transmission line valve that might be required during any emergency, and take prompt remedial action to correct any valve found inoperable.

As noted by industry, most operators already have a SCADA system in place. Therefore, PHMSA is proposing that operators must have a SCADA system to implement IM measures for managing Class 1 to Class 3 location changes. A SCADA system will help operators detect leaks and other pressure loss situations more rapidly. In addition, PHMSA is proposing that remote-control valves and automatic shutoff

[103] For instance, following the PG&E incident at San Bruno, CA, PG&E rapidly installed automatic shutoff valves where possible and stated there was sufficient basis to deploy such valves. However, company documents from 2006 stated that the company had concluded that most of the damage from a rupture would take place in the first 30 seconds before shut-off valves could stop the flow of gas and declined to install the valves in the area.

[104] *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf.* ''Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, CA, September 9, 2010.''

valves installed per this NPRM must be controlled and monitored by a SCADA system and promptly closed to isolate the pipeline segment should a rupture occur. As such, and similar to how pipelines with exclusionary conditions would be handled, operators without a SCADA system could apply for a special permit to implement IM in lieu of pipe replacement when class locations change.

M. Traceable, Verifiable, and Complete Records for Supporting Class-Location-Change Integrity Management Measures

1. Summary of ANPRM Questions 5, 5a, and 5b

In question 5 of the ANPRM, PHMSA requested comments on introducing requirements for TVC records, including what records would be required, and how and when they could be obtained, to support any IM measures that would be performed to manage class location changes. More specifically, PHMSA asked whether necessary TVC record should include pipe properties, including yield strength, seam type, and wall thickness; coating type; O&M history; leak and failure history; pressure test records; MAOP; class location; depth of cover; and ability to be in-line inspected.

2. Summary of Comments

NAPSR, the PST, and the California Public Advocates Office supported requiring TVC records for segments where operators would like to manage class location changes by using IM measures. NAPSR also asserted, and PST agreed, that historically poor recordkeeping practices should be considered a potential indicator of risk, as mapping issues have often been found to be latent conditions or indicators of higher risk in pipeline accidents.

More specifically, the California Public Advocates Office supported the idea that PHMSA require in the regulation TVC records for yield strength, seam type, and wall thickness, and it suggested adding outside diameter as an additional pipe property to consider. It stated that records, if available, should be obtained by the operator within 2 years of the class location change. If these records were unavailable, the California Public Advocates Office supported allowing an operator to request a special permit from PHMSA.

NAPSR and the PST stated that, given that records can be acquired or created if necessary (*i.e.,* through a pressure test, pipe specification verification, and lab tests), if an operator does not have the appropriate records, PHMSA should not allow an operator to use IM measures to manage class location changes. Both NAPSR and the PST noted that operators should be leveraging ILI technology to create records needed for regulatory compliance by, at a minimum, employing tools that can effectively identify corrosion, dents, gouges, cracks, and interactive defects.

The Associations, GPA Midstream, and multiple operators requested that TVC records only apply to MAOP verification, and that a lack of records should not make a pipeline segment ineligible for using IM to manage class location changes. They also noted that, should TVC records not be available for pipeline segments undergoing a class location change, the 2016 Gas Transmission NPRM provides a way for operators to obtain those records and take appropriate safety options within 24 months of the class location change. Further, they stated that additional records may be required for ILI-identified anomaly analysis and will be collected.

Kinder Morgan added that the TVC standard is not intended for many records used in IM processes. TransCanada Corporation stated that while TVC records are helpful and would improve site-specific assessments, they are not critical for an operator to perform IM measures given that adequate testing or conservative assumptions may be employed.

An individual citizen commented that for IM measures specifically, ILI technology implementation, design records, and pressure test records are necessary for anomaly assessment. As stated by this citizen, pressure test information is only required for assessing longitudinal seam anomalies and is only valuable if the test was conducted to at least 1.25 times MAOP. The commenter also asserted that record ''completeness'' should be determined based on the required use of the information. Given that design pressure is calculated with outside diameter, wall thickness, and SMYS, records that supply these values should be considered ''complete'' if the data is used to calculate design pressure, according to this individual. Finally, the commenter noted that coating type is not nearly as important as coating condition, and depth of cover is a practical concern, especially in agricultural areas, yet is not required in § 192.611 and was not required prior to the promulgation of the natural gas regulations in 1970.

3. PHMSA Response

PHMSA agrees with certain commenters that documentation and recordkeeping are very important and has included a proposed requirement that operators keep records of the pipeline assessments, surveys, remediations, maintenance, analyses, and any other action implemented to comply with the requirements proposed under this rulemaking for managing Class 1 to Class 3 location changes using the IM for the life of the pipeline.

Per this rulemaking, operators would need to have, or otherwise obtain, TVC material-properties records (*e.g.,* diameter, wall thickness, yield strength, seam type, and coating type) to implement the proposed IM alternative for managing a pipeline segment that has changed from a Class 1 to a Class 3. These types of material properties records are necessary for a PSR-compliant IM program [105] and MAOP determination.[106]

As commenters noted, the 2019 Gas Transmission Final Rule provides a mechanism for operators to obtain TVC material property records if they are missing, and the 24-month compliance window of this NPRM provides operators with adequate time to obtain those records, if needed. As specified in the 2019 Gas Transmission Final Rule, if operators are missing any material property records needed when performing anomaly evaluations and repairs, operators must confirm those material properties under §§ 192.607 and 192.712(e) through (g). Records created in accordance with § 192.607 must be maintained for the life of the pipeline and must be TVC; therefore, if an operator would need to create material records prospectively to be eligible for the IM alternative, those records would be TVC.

N. Data on Class Location Pipe Replacement and Route Planning

1. Summary of ANPRM Questions 7 and 8

In the ANPRM, PHMSA requested data regarding operators' compliance with current class change pipe replacement requirements, including the amount of pipe being replaced, the number of distinct locations where pipe

[105] Operators need TVC records to repair anomalies and for IM measures that depend on design properties.

[106] TVC records are required for MAOP determination. To be TVC, a record must be clearly linked to the original information about a pipeline segment or facility; confirmed by other complementary, but separate, documents; and finalized by a signature, date, or other appropriate marking.

was being replaced, and the associated costs.

PHMSA also requested comments on whether and to what extent operators consult growth and development plans during route planning.

2. Summary of Comments

PHMSA received various technical data provided by individual operators and trade associations regarding the amount of pipe being replaced, the number of locations at which pipe was replaced, and the associated costs.

Pertaining to route planning, the responses PHMSA received from industry, individuals, and groups alike stated that operators consider future building plans along a proposed pipeline route when considering both the route and pipe materials. NAPSR asserted that most operators are currently defaulting to Class 3 requirements for all newly installed pipe. NAPSR also stated concern with allowing operators to use IM principles for managing class location changes in that it could discourage operators from continuing this conservative practice.

3. PHMSA Response

PHMSA considered the data it received on class location change pipe replacement when developing the PRIA; see that document for further discussion on the data received and the subsequent assumptions and analysis PHMSA made and performed.

Regarding operators considering growth and development plans when route planning, PHMSA will note that operators must monitor and implement class location changes based on the required study requirements of § 192.609 and confirm or revise MAOP based on the requirements in § 192.611. Pipeline segments that experienced a class change before the date of the rule would not be eligible to apply the IM approach to managing the class location change, but operators could still apply for a special permit to manage these pipeline segments with IM.

O. Other Topics—General Comments

The following relevant comments received were of a general nature or did not pertain to questions considered in the ANPRM.

The PST and multiple individuals from the public requested that PHMSA host public meetings and webinars early in the rulemaking process to educate the public on the current and proposed class location change regulations. The Pipeline Safety Coalition stated that PHMSA doing so would facilitate a safety culture based on holistic participation from informed parties.

State representatives from the State of New Jersey's 14th, 15th, 16th, and 18th legislative districts commented that New Jersey requires that intrastate pipelines be constructed to Class 4 location design requirements, regardless of population density. They encouraged PHMSA to consider adopting New Jersey's stricter intrastate requirements for interstate assets.

The California Public Advocates Office supported PHMSA's effort to streamline the current class location regulations as it believed it would be advantageous to both operators and regulators. It also requested that PHMSA re-evaluate the definition of a Class 4 location to include stadiums or concert venues, which would not qualify currently but present significant public safety consequences.

Based on certain aspects of the ANPRM, GPA Midstream expressed concern about PHMSA's commitment to making meaningful improvements to the class location regulations, stating that PHMSA is suggesting ''unrelated issues identified in previous advisory bulletins or during routine inspections are relevant to the decision of whether to update the class location regulations'' and that the agency suggests ''topics that are already being addressed in a separate rulemaking proceeding should limit an operator's ability to obtain class location relief.'' They did, however, support adding more options for an operator to address class location changes.

The Associations and TransCanada Corporation suggested that currently issued special permits could be retired when an operator demonstrates that all conditions have been satisfied and that the class location change is managed to an acceptable level of safety.

As an additional consideration to the class location change regulations, the Associations suggested other regulations that would be affected, such as those at § 192.625 for odorization, should be adjusted. They specifically requested that PHMSA allow alternative P&M measures in lieu of odorization. Further, they also commented that an operator using integrity assessments for class location change management should also be allowed to uprate their MAOP in accordance with subpart K.

The Associations also requested that PHMSA implement an expedited interim process for class location changes, which would allow operators to manage class location changes through integrity assessments prior to implementation of the final rule. They contend that this regulatory update has been in the works for 15 years, and cost efficiencies realized by this change would enhance operator ability to fund integrity assessment technology development.

The Associations expressed support for PHMSA including additional fields in the annual report to collect information on class location designation, integrity assessments, or data on other class change management operators use. Furthermore, they requested that PHMSA implement annual report changes to replace what they identified as excessive reporting and notifications required for special permits.

Finally, the Associations commented that PHMSA's singular focus on pipe stress is misplaced and outdated given that modern integrity assessment technology can provide equivalent safety factors to stress-reducing measures.

1. Response to General Comments

Regarding the New Jersey State legislators' comment, PHMSA recognizes that New Jersey may have more conservative design requirements for new intrastate gas transmission pipelines than what is being proposed in this NPRM; however, implementing these requirements would not support the NPRM focus of managing class location changes safely in existing pipelines.

PHMSA is proposing that segments uprated in accordance with subpart K may be allowed to use this proposed rule for class location change management, but only if the segment has had a subpart J pressure test to at least 1.39 times MAOP [107] and meets all the requirements of the proposed rule, including those regarding records. Segments uprated without a subpart J pressure test would be excluded under this proposed rule.

Regarding the comments from TransCanada and the Associations on the class location definitions, odorization requirements, and special permit ''retirement'' provisions, PHMSA has determined to propose alternative requirements to those currently imposed on pipeline segments experiencing a change in class location in this NPRM.

PHMSA is not proposing an expedited interim process for class location changes as a part of this NPRM. In the absence of these proposed regulatory

[107] PHMSA acknowledges that § 192.555 allows uprating based upon the highest pressure allowed in § 192.619, which would require a 1.50 times MAOP for a Class 3 location. Since Class 1 location pipe would only be tested to either 1.1 or 1.25 times MAOP based upon § 192.619, the proposed rule change would require a 1.39 times MAOP for uprating the MAOP where operating pressures of a segment have been lowered for other existing Class 1 to Class 3 location changes.

changes, operators can currently apply for a special permit to manage class location changes in a similar manner. Part of the intent of this NPRM is to codify much of the current special permit process into the regulations, thereby providing greater regulatory certainty and a streamlined process for class location change management for eligible pipe segments.

PHMSA respectfully disagrees that a singular focus has been placed on pipe stress. PHMSA is concerned with every threat to pipeline integrity and how they can be remediated to maintain safety. PHMSA also disagrees that the reporting requirements for the current special permit process are excessive. The special permit process is an optional process that operators can opt into. If the requirements are excessive, operators can comply with the regulations as they are written. With that said, PHMSA may consider revising the annual report as needed when finalizing this rulemaking.

IV. Section-by-Section Analysis

§ 191.22 National Registry of Pipeline and LNG Operators

Section 191.22 details events that require a notification to PHMSA. PHMSA has proposed the addition of requiring operators to notify PHMSA if they use IM to manage pipeline segments that have changed from a Class 1 to a Class 3 location. This prompt notification would provide PHMSA an opportunity to oversee the operator's implementation of the proposed Class 1 to Class 3 location segment regulations.

§ 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of the regulations proposed in this NPRM, PHMSA is proposing new definitions for the terms ''Class 1 to Class 3 location segment'' and ''in-line inspection segment.'' These two terms define the segments to which the requirements of the proposed § 192.618 would apply.

A ''Class 1 to Class 3 location segment'' would be defined as the segment of pipe where the class location has changed from a Class 1 to a Class 3 location and where the operator intends to confirm or revise the MAOP by using the IM alternative in this proposed rulemaking. The Class 1 to Class 3 location segment will consist of the pipe that was designed to Class 1 specifications, per subpart C, that is in a newly identified Class 3 location.

An ''in-line inspection segment'' would be defined as including all pipe upstream and downstream of the Class 1 to Class 3 location segment that is between the nearest upstream ILI launcher and the nearest downstream ILI receiver and the Class 1 to Class 3 location segment.

PHMSA is also proposing a definition for ''predicted failure pressure'' to provide additional clarification to the regulations. A ''predicted failure pressure'' would be defined as the calculated pipeline anomaly failure pressure based on the use of an appropriate engineering evaluation method for the type of anomaly being assessed and without any safety factors.

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

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA is making conforming amendments to § 192.7 to reflect other changes adopted in this final rule.

API Standard 1163, which is already incorporated by reference into the regulations for natural gas transmission pipelines at § 192.493 and for hazardous liquid pipelines at § 195.591, covers the use of ILI systems for onshore and offshore gas and hazardous liquid pipelines. This standard includes, but is not limited to, tethered, self-propelled, or free-flowing systems for detecting metal loss, cracks, mechanical damage, pipeline geometries, and pipeline location or mapping. The standard applies to both existing and developing technologies, and it is an umbrella document that provides performance-based requirements for ILI systems, including procedures, personnel, equipment, and associated software.

In this NPRM, PHMSA is proposing to incorporate this standard by reference into the proposed IM alternative at § 192.618(b)(4) to require operators validate ILI results to Level 3 in accordance with API Standard 1163. Per API Standard 1163, a Level 3 validation is one where ''extensive validation measurements are available that allow stating the as-run tool performance. Validating to such a level allows an operator to establish a direct link between the ILI tool performance and the impact it has on IM decisions.'' PHMSA requests comment as to whether it should allow operators to validate ILI results to Level 2 or Level 3 per API Standard 1163. Per API Standard 1163, a Level 2 validation is ''where no definitive statement is made about the actual tool performance. Although it is possible to state with a high degree of confidence whether the tool performance is worse than the specification, the approach does not allow one to state with confidence that the tool performance is within specification.''

Further, PHMSA is proposing to incorporate by reference ASME/ANSI B31.8S–2004 for proposed § 192.618. B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective IM program utilizing proven industry practices and processes. Effective system management can decrease repair and replacement costs, prevent malfunctions, and minimize system downtime.

§ 192.611 Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure

Section 192.611 prescribes requirements for operators when a change in class location has occurred. With the development of the IM alternative in proposed § 192.618, conforming changes would be needed to this section to specify that an operator may confirm or revise the MAOP of a Class 1 to Class 3 segment in accordance with proposed § 192.618. A pressure reduction taken in accordance with this section and after the effective date of this rule would not preclude an operator from implementing an integrity assessment program per paragraph (a)(4) of this section at a later date. Further, an operator would need to implement such a program prior to any future increases of MAOP. For the purposes of this section, operators will not be allowed to use pressure reductions taken prior to the effective date of the rule for Class 1 to Class 3 locations. Operators who wish to do so would be required to apply to PHMSA for a special permit.

§ 192.618 Class 1 to Class 3 Location Segment Requirements

Section 192.618 establishes the proposed conditions an operator would implement in its O&M procedures if it chooses to manage pipeline segments where the class location has changed from a Class 1 to a Class 3 through the IM alternative. PHMSA notes that the approach outlined in this NPRM would apply only to those pipeline segments that have changed class location following the effective date of the rulemaking; operators would not be able to use the IM alternative retroactively for pipeline segments that have experienced a class location change prior to this rulemaking.

The proposed requirements in this NPRM are based on PHMSA's extensive experience with evaluating special permit applications and granting special permits that effectively apply specific safety requirements on a case-by-case basis.

Per this proposal, operators would designate the Class 1 to Class 3 location segment as an HCA, as that term is defined in § 192.903, and include the segment in its IM program in accordance with subpart O. Operators would also inspect all pipe between the nearest upstream ILI launcher and nearest downstream ILI receiver that contains the pipeline segment changing from a Class 1 to a Class 3 location when performing an ILI assessment of the Class 1 to Class 3 location segment.

PHMSA has proposed certain conditions, similar to its practice for special permits, that would preclude the use of this IM alternative for managing class location change segments for pipeline segments with certain higher-risk attributes. More specifically, the proposed minimum pipe eligibility criteria are based on the previously published guidance in the 2004 **Federal Register** Notice. As outlined in that criteria and this NPRM, certain pipeline segments would not be eligible for the IM alternative because they are higher risk and warrant a case-by-case review per the special permit process.

PHMSA proposes a pipeline segment would be ineligible to use the IM alternative if any of the following conditions exist on that segment:

- Pipeline segments that operate above 72 percent SMYS.
- Pipeline segments with bare pipe (*i.e.,* uncoated pipe).
- Pipeline segments with wrinkle bends.
- Pipeline segments that are missing records for diameter, wall thickness, grade, seam type, yield strength, and tensile strength.
- Pipeline segments without a hydrostatic test conducted with a test pressure of at least 1.25 times MAOP.
- Pipe with DC, LF–ERW, EFW, or lap-welded seams, or pipe with a longitudinal joint factor below 1.0.
- Pipe with cracking in the pipe body, seam, or girth welds in the segment, or within 5 miles of the segment, that is over 20 percent of the pipe wall thickness, has a predicted failure pressure less than either 100 percent of SMYS or 1.5 times MAOP, or has experienced a leak or a rupture due to brittle failure mode. Should a pipeline segment changing from a Class 1 to a Class 3 location at any time fail the requirements regarding cracking, that segment would no longer be eligible for the IM alternative for class location change management, and the operator would be required to replace the segment within 2 years of the ineligibility determination. Prior to the replacement, the enhanced crack repair conditions as detailed below would apply.
- Pipeline segments with tape coatings or shrink sleeves, or with poor external coating that requires the use of a 100 millivolt shift or linear anodes to maintain required levels of CP.
- Pipeline segments that transport gas whose composition quality is not suitable for sale to gas distribution customers.
- Pipeline segments that operate under § 192.619 (c) or (d).
- Pipeline segments, or portions of pipeline segments, that have been denied a class location change special permit in the past.

This section also contains proposed requirements for operators to conduct their initial integrity assessment within 24 months of the Class 1 to Class 3 location segment change, which would be consistent with existing requirements for the deadline to reconfirm or revise a pipeline segment's MAOP when its class location changes; the specific ILI integrity assessment methodology, including ILI results validation, that operators must use; and additional repair criteria for these segments that supplements the existing repair criteria in subpart O.

For the purposes of ILI tool calibration and validating ILI results, an operator may use previously excavated anomalies or recent anomaly excavations with known dimensions that were field measured for length, depth, and width; externally re-coated; CP maintained; and documented for ILI calibrations prior to the ILI tool run. ILI tool calibrations must use ILI tool run results and anomaly calibrations from either the Class 1 to Class 3 location segment or from the complete ILI tool run in the in-line inspection area. A minimum of four calibration excavations should be used for unity plots.

Regarding the additional repair criteria, subpart O allows metal loss anomalies to grow until the predicted failure pressure is 1.1 times MAOP (*i.e.,* a 10 percent safety factor). PHMSA believes the more stringent repair criteria proposed in this NPRM is needed to compensate for the lack of newly replaced pipe in locations changing from a Class 1 to a Class 3. The existing pipe in these locations could include pipelines that were built before design and construction standards were promulgated in 49 CFR part 192. Such existing pipe may not have the steel toughness to mitigate ruptures when the pipe is corroded, dented, or has any cracking in the pipe body or pipe seam.

As such, PHMSA is proposing additional anomaly inspection and repair criteria as follows:

- Operators must use high-resolution ILI methods for performing integrity assessments.
- Integrity assessments for pipeline segments where the class location has changed from Class 1 to Class 3 must also include all pipe upstream and downstream of the segment between the nearest upstream ILI launcher and the nearest downstream ILI receiver. This segment would be defined as the ''in-line inspection segment.''
- Operators would conduct non-destructive SCC inspections any time pipe in the in-line inspection segment is exposed (except for times a pipe segment is exposed by a third party through a ''one-call'' excavation under § 192.614) and where the operator finds disbonded or repaired coating (except for pipe that is coated with fusion-bonded or liquid-applied epoxy coatings).

For ILI anomalies identified in the in-line inspection segment, PHMSA proposes the following repair criteria that is consistent with granted special permit conditions: Immediate repair conditions for pipe threats such as metal loss, denting, cracking, and other anomalies that are at or near the point of failure. These include metal loss with a predicted failure pressure less than or equal to 1.1 times the MAOP, crack-type defects with a predicted failure pressure less than 1.25 times the MAOP, and additional specified criteria dependent on anomaly type and size.

To ensure anomalies in the in-line inspection segment are repaired in a timely manner, PHMSA is proposing for operators to repair scheduled anomalies in 1 year regardless of whether the applicable pipeline segment is in an HCA. One-year scheduled conditions are for pipe threats such as metal loss, denting, cracking, and other anomalies that are not an immediate threat to integrity but that operators would need to repair promptly. PHMSA is also proposing to incorporate a tiered approach for the predicted failure pressure criteria for metal loss and crack anomalies based on the class location at the anomaly to make the criteria more stringent as the class location increases. In addition to repair criteria based on predicted failure pressure, PHMSA is basing the proposed dent repair criteria on anomaly size and location. For Class 1 to Class 3 location segments, PHMSA has also established monitored conditions for pipe threats such as metal loss denting, cracking, and other anomalies that are not severe enough to need prompt repair but that the operator must monitor.

PHMSA is also proposing additional repair criteria for anomalies identified in the Class 1 to Class 3 location segment beyond the criteria proposed for the in-line inspection segment. These criteria include more conservative criteria for crack anomalies and a requirement for operators to repair discovered pipe wall thickness loss greater than 40 percent within 1 year. These criteria are based on PHMSA research and development projects and were developed in conjunction with the repair criteria that the GPAC discussed and voted to adopt in 2019.

In addition, PHMSA is proposing the following maintenance surveys to address threats not assessed by ILI and the findings remediated, as well as other P&M actions:

- CIS,
- CP test site survey,
- Line-of-sight markers,
- Interference survey,
- Depth-of-cover survey,
- Right-of-way patrols,
- Leakage survey, and
- Shorted casings survey.

PHMSA also proposes requiring operators install remote-control or automatic shutoff valves, or otherwise equip existing valves with remote-control or automatic shutoff capability for the mainline block valves both upstream and downstream of the class location upgrade segment. In this proposed rule, PHMSA is defining the timing for remote-control and automatic shutoff valve closure should there be a pipeline rupture and is requiring operators use a SCADA system if managing class location changes through IM. More specifically, PHMSA is proposing a 30-minute valve closure standard to be consistent with conditions it has required operators to meet in certain class location change special permits. This 30-minute standard would help protect populations where Class 1 pipe is not being upgraded and will remain in the ground. If operators determine they would not be able to meet this 30-minute valve closure standard as a part of the IM alternative in this NPRM, an operator could apply to PHMSA for a special permit for managing their class location change.

PHMSA is also requiring documentation for pipe properties, pressure tests, ILI assessments, surveys, and any other required action operators take to comply with this proposed rulemaking.

Finally, if an operator intends to use the IM alternative to manage a pipeline segment that has changed from a Class 1 to a Class 3 location, the operator must submit a notification to PHMSA within 60 days of the class location change, in accordance with § 191.22(c)(2). Such a notification must include details of each pipeline segment that experienced a class location change that the operator will manage using IM.

PHMSA requests comments on whether it should consider modifying or eliminating any of the O&M procedural requirements of this section, including:

(a) Program requirements, including the eligibility conditions, for a Class 1 to Class 3 location segment.

(b) Pipeline integrity assessments.

(c) Remediation schedule (In-line inspection segment).

(d) Special requirements for crack anomalies.

(e) Pipe and weld cracking inspections.

(f) Additional preventive and mitigative measures.

(g) Remote-control or automatic shutoff valves.

(h) Documentation.

(i) Notifications to PHMSA of integrity assessment program for class 1 to class 3 location segment changes.

If a commenter determines that any of the above requirements should be modified or eliminated, please explain how such a modification or elimination would maintain, increase, or decrease the current level of pipeline safety and environmental protection. Based on comments received, PHMSA may consider modifying or eliminating the above requirements if they are not necessary for maintaining pipeline safety or protecting the environment and another approach would maximize net benefits to society.

§ 192.712 Analysis of Predicted Failure Pressure and Critical Strain Levels

In the ''Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments'' final rule published on October 1, 2019, PHMSA updated and codified minimum standards for determining the predicted failure pressure of pipelines containing anomalies or defects associated with corrosion metal loss and cracks. In this NPRM, PHMSA is proposing repair criteria for the in-line inspection segment and the Class 1 to Class 3 location segment, which include repair criteria for dents. Some of the proposed dent repair criteria allows operators to determine critical strain levels for dents and defer repairs if critical strain levels are not exceeded. In this section, PHMSA has established minimum standards for calculating critical strain levels in pipe with dent anomalies or defects and has included those standards in a new paragraph (c). These standards are based off of the dent ECA method discussed and voted on as part of the repair criteria discussion at the Gas Pipeline Advisory Committee meetings during March 26–28, 2018. The title of this section has also been updated to reflect this addition.

§ 192.903 What definitions apply to this subpart?

Section 192.903 provides definitions for various terms used throughout part 192 subpart O. In support of the regulations proposed in this NPRM, PHMSA is proposing to amend the definition of ''high consequence area.'' The revised definition would require operators to incorporate any Class 1 to Class 3 location segment, as defined in proposed § 192.3, into their IM programs as an HCA.

V. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This proposed 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 the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Further, section 60102(*l*) requires the Secretary, to the extent appropriate and practicable, to update incorporated industry standards that have been adopted as a part of the pipeline safety regulations. The Secretary has delegated the authority vested in the Secretary by the Pipeline Safety Law to the PHMSA Administrator under 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866, Regulatory Planning and Review, (58 FR 51735; Oct. 4, 1993), requires agencies to regulate in the ''most cost-effective manner,'' to make a ''reasoned determination that the benefits of the intended regulation justify its costs,'' and to develop regulations that ''impose the least burden on society.'' The Executive Order and DOT regulations governing rulemaking procedures (49 CFR part 5) require that PHMSA submit ''significant regulatory actions'' to OMB for review. The proposed rulemaking is a ''significant regulatory action'' under section 3(f) of Executive Order 12866 and DOT rulemaking regulations. The proposed rulemaking has been reviewed by the Office of Management and

Budget in accordance with Executive Order 12866 and is consistent with the Executive Order 12866 requirements and 49 U.S.C. 60102(b)(5)–(6).

The tables below summarize the annualized cost savings for the provisions in the proposed rule. PHMSA anticipates that, if promulgated, the proposals in this NPRM would have economic benefits to the public and the regulated community by reducing cost burdens without increasing risks to public safety or the environment. These estimates reflect the assumption that the IM alternative for managing class location changes proposed in this rule will be a less-costly alternative to the current regulatory requirements.

PHMSA estimates that the proposed rule will result in annualized cost savings of approximately $55 to $86 million per year, based on its analysis of two different scenarios and at a 7 percent discount rate.[108] The tables below present the annualized costs for the baseline and this proposed rule, for both scenarios examined, at a 3 percent and a 7 percent discount rate:

ANNUALIZED PROPOSED RULE COST SAVINGS, SCENARIO 1

[2020–2039, millions]

	Discount rate	
	3%	7%
Baseline *		
Pipe Replacement	$206.7	$206.7
Special Permits	9.0	8.0
Total Cost	215.7	214.7
Proposed Rule		
Pipe Replacement	135.8	135.8
Special Permits	2.5	2.2
New Compliance Method	23.8	21.8
Total Cost	162.1	159.8
Net Annualized Cost	−53.6	−54.9

* Operators also have the option to use a pressure test or pressure reduction to manage the class location change. To the extent operators find the new class location MAOP acceptable, the decision by operators to use these options is not affected by the addition of the proposed rule compliance method. Therefore, the rule has no incremental effect on these compliance options.

ANNUALIZED PROPOSED RULE COST SAVINGS, SCENARIO 2

[2020–2039, millions]

	Discount rate	
	3%	7%
Baseline *		
Pipe Replacement	$326.7	$326.7
Special Permits	9.0	8.0
Total Cost	335.7	334.7
Proposed Rule		
Pipe Replacement	214.6	214.6
Special Permits	2.5	2.2
New Compliance Method	34.8	31.8
Total Cost	251.9	248.7
Net Annualized Cost	−83.8	−86

* Operators also have the option to use a pressure test or pressure reduction to manage the class location change. To the extent operators find the new class location MAOP acceptable, the decision by operators to use these options is not affected by the addition of the proposed rule compliance method. Therefore, the rule has no incremental effect on these compliance options.

[108] Scenario 1 averaged PHMSA's estimates, annually and from a low- and high-end concept, of the number of miles that would change from a Class 1 to a Class 3 location and where operators would use the IM alternative. This estimate was 77.6 miles per year. Scenario 2 took the median of PHMSA's estimates, annually and from a low- and high-end concept, and this estimate was 117.6 miles per year. See Section 3 of the Preliminary Regulatory Impact Analysis for more details.

For more information, please see the PRIA in the docket for this rulemaking.

C. Executive Order 13771

This proposed rule is expected to be a deregulatory action under Executive Order 13771. Details on the estimated costs of this proposed rule can be found in the PRIA in the rulemaking docket.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) requires federal agencies to review each rulemaking action to consider whether it would have a ''significant economic impact on a substantial number of small entities'' to include small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations under 50,000. This NPRM was developed in accordance with Executive Order 13272, ''Proper Consideration of Small Entities in Agency Rulemaking'' (68 FR 7990, Feb. 19, 2003) and DOT's procedures and policies to promote compliance with the RFA and to ensure that the potential impacts of a regulatory action on small entities were properly considered.

Based on the analysis within the PRIA in the rulemaking document, which PHMSA has summarized below, PHMSA expects that this rulemaking will not have a significant economic impact on a substantial number of small entities. However, PHMSA seeks public comment on its analysis.

(1) Statement of the Need for, and Objectives of, the Rulemaking

In this rulemaking PHMSA proposes to add an alternative set of requirements within the PSR that operators could use, based on implementing integrity management principles and pipe eligibility criteria, to manage certain pipeline segments where the class location has changed from a Class 1 location to a Class 3 location. Through required periodic assessments, repair criteria, and other extra preventive and mitigative measures, PHMSA expects this alternative approach would providing cost savings for pipeline operators without adversely affecting safety. The need for and objectives of this rulemaking are discussed further above in Section I.A (''Purpose of Regulatory Action'').

(2) Description of the Small Entities That Could Be Affected by the Rulemaking and Their Estimated Compliance Costs

The RFA obliges PHMSA to assess whether the rulemaking would have ''a significant impact on a substantial number of small entities. This assessment involves (1) identifying the domestic parent entities for affected operators, (2) determining which are small entities based on Small Business Administration size criteria, and (3) assessing the potential impact of the rule on those small entities based on estimated entity-level annualized compliance cost savings and annual revenues. Although PHMSA's analysis on each of these issues is provided in greater detail within the PRIA in the rulemaking docket, that analysis is summarized below.

There are currently 1,099 operators of onshore natural gas transmission pipelines, and approximately 85 percent, or 939 operators operate Class 1 pipelines. PHMSA estimates that operators of Class 1 pipelines are owned by 324 parent entities, and of these, 254 are small entities. Small entities operate approximately 5,200 miles of Class 1 pipeline, which is only about 2.2 percent of all Class 1 pipeline.

The NPRM does not eliminate any of the currently available options for management of changes from Class 1 to Class 3, but would rather provide flexibility to operators by enabling the use of another compliance option. Since PHMSA expects that the approach introduced in this NPRM would cost less than the other predominately used options—pipeline replacement and special permit—such that small entities would have the opportunity to achieve cost savings should they need to manage class location changes in the future for pipeline segments that meet the eligibility criteria set forth in this NPRM.

The quantity, character, and location of future class changes is highly uncertain, particularly on a year-to-year basis. In any given year, only a subset of pipelines will experience a change from Class 1 to Class 3. PHMSA is not able to develop an annual forecast describing specific pipeline segments changing classes or to what extent those changes will be managed by small versus large operators. Over the 20-year period of analysis, PHMSA assumes that each pipeline operator will manage a share of the future changes from Class 1 to Class 3 that is proportional to the total miles of Class 1 pipeline it operates.

PHMSA estimates that small entities will manage an aggregate 1.7 to 2.6 miles of pipeline changing from Class 1 to Class 3 annually, in Scenarios 1 and 2, respectively. Aggregate annualized cost savings for small entities is estimated to be $1.17–$1.19 million in Scenario 1, using 3 and 7 percent discount rates, respectively; annualized small entity savings is $1.8–$1.9 million in Scenario 2. Under Scenario 1, the average annual cost savings per small entity is $4,700, with a median savings of $1,500 per year. Under Scenario 2, the average per-entity annual savings is $7,400, with a median of $2,300.

PHMSA estimates only about 1 percent of Class 1 pipeline miles will be affected by a change to Class 3 in total over the next 20 years. Based on PHMSA's high-end Scenario 2 estimate of 117.6 miles per year, only 2,352 miles will make this change over the next 20 years. Annually, the proposed rule affects 0.05 percent of Class 1 miles. The characteristics of this small subset of affected pipeline miles (or segments) will ultimately determine the extent to which large and small entities ultimately avail themselves of the proposed rule option. Given that small entities operate only about 2 percent of Class 1 miles, large entities in the aggregate are more likely to experience a pipeline segment requiring a change from Class 1 to Class 3.

It is also important to note that although the savings are presented here on an annualized basis, the vast majority of small entities will likely not have to manage a change from Class 1 to Class 3 for any pipeline miles in a given year. For instance, PHMSA's estimate of 1.7 to 2.6 miles per year of Class 1 to Class 3 changes managed by small entities (Scenarios 1 and 2), and PHMSA's estimated average segment length of 0.26 miles, suggests an average of 7 to 10 segments per year experiencing a change from Class 1 to Class 3 across the entire pipeline industry. If each operator only manages one segment changing from Class 1 to Class 3 each year, then only 7 to 10 small entities (or fewer if operators manage multiple segments in one year) may manage a Class 1 to Class 3 change per year, out of 254 total affected small entities.

(3) Significant Alternatives Considered

PHMSA does not expect this proposed rulemaking to have a significant economic impact on small businesses. Further, the changes to the PSR proposed in this NPRM are generally intended to provide regulatory flexibility and cost savings to industry members without adversely affecting safety. PHMSA solicits public comment on the economic impact on small entities, and potential alternatives that reduce any economic impact on small entities.

(4) Duplicative, Overlapping, and Conflicting Federal Rules

PHMSA is unaware of any Federal regulations that are substantially similar to the proposals in this NPRM and which would duplicate, overlap, or conflict with the PSR revisions proposed.

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

PHMSA analyzed this proposed rule per the principles and criteria in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249; Nov. 6, 2000) and under DOT Order 5301.1. Because PHMSA does not anticipate that this proposed rule will have tribal implications, the funding and consultation requirements of Executive Order 13175 would not apply. PHMSA seeks comment on the applicability of the Executive Order to this proposed rule.

F. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) establishes policies and procedures for controlling paperwork burdens imposed by Federal agencies on the public. Pursuant to 44 U.S.C. 3506(c)(2)(B) and 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. The proposals in this NPRM will trigger new notification requirements for pipeline operators who experience a change in their class location.

PHMSA proposes to create a new information collection to help operators comply with the proposed revision to the PSR. Operators will be required to notify PHMSA if they choose to use an alternative to an inline-inspection device when conducting pressure tests on their pipelines. Operators will also be required to notify PHMSA if they use integrity management protocols to manage pipeline segments that have changed from a Class 1 to a Class 3 location. PHMSA will request a new Control Number from OMB for this new information collection.

PHMSA will submit an information collection request to OMB for approval based on the proposed requirements in this NPRM. The information collection is contained in the PSR, 49 CFR parts 190–199. The following information is provided for this 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 is estimated as follows:

1. Title: Class Location Change Notification Requirements.

OMB Control Number: Will request from OMB.

Current Expiration Date: TBD.

Abstract: This information collection covers the collection of data from owners and operators of pipelines. Pipeline operators are required to notify PHMSA in the event of certain instances that pertain to a change in their class location.

Affected Public: Owners and operators of pipelines.

Annual Reporting Burden:

Total Annual Responses: 100.

Total Annual Burden Hours: 25.

Frequency of Collection: On occasion.

Requests for a copy of this information collection should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline 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 December 14, 2020. Comments may also be sent via email to the Office of Management and Budget at the following address: *oira_submissions@omb.eop.gov.*

G. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1501 *et seq.*) requires Federal agencies to prepare and consider estimates of the budgetary impact of regulations containing Federal mandates upon State, local, and Tribal governments before adopting such regulations. This NPRM imposes no unfunded mandates. If promulgated, this rule would not result in costs of $100 million, adjusted for inflation, or more in any one year to either State, local, or Tribal governments, in the aggregate, or to the private sector. A copy of the PRIA is available for review in the docket.

H. National Environmental Policy Act

The National Environmental Policy Act (NEPA) (42 U.S.C. 4321 *et. seq.*) requires Federal agencies to prepare a detailed statement on major Federal actions significantly affecting the quality of the human environment. PHMSA analyzed this NPRM in accordance with NEPA, Council on Environmental Quality regulations (40 CFR parts 1500–1508), and DOT Order 5610.1C. PHMSA has prepared a draft Environmental Assessment (EA) and has preliminarily determined this action will not significantly affect the quality of the human environment. A copy of the EA for this action is available in the docket. PHMSA invites comment on the environmental impacts of this proposed rulemaking.

I. Executive Order 13132: Federalism

Executive Order 13132, ''Federalism'' (64 FR 43255; Aug. 10, 1999) imposes certain requirements on Federal agencies formulating or implementing policies or regulations that preempt State law or that have federalism implications. This NPRM does not impose a substantial, direct effect 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. This NPRM also does not impose substantial direct compliance costs on State and local governments.

The proposed rule could have preemptive effect because the pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibit State safety regulation of interstate pipelines. Under the pipeline safety law, States can augment pipeline safety requirements for intrastate pipelines but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility not otherwise covered by PHMSA regulations. In this instance, the preemptive effect of the proposed rule is limited to the minimum level necessary to achieve the objectives of the pipeline safety laws under which the proposed rule is promulgated. Therefore, the consultation and funding requirements of E.O. 13132 do not apply.

J. Executive Order 13211

This proposed rule is not a ''significant energy action'' under Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355; May 22, 2001). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this proposed rule as a significant energy action.

K. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR 19476), at *http://www.dot.gov/privacy.*

L. 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 can be used to cross-reference this action with the Unified Agenda.

List of Subjects

49 CFR Part 191

Class location change reporting, pipeline reporting requirements.

49 CFR Part 192

Class location change, integrity management, pipeline safety.

In consideration of the foregoing, PHMSA is proposing to revise 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.,* and 49 CFR 1.97.

■ 2. Amend § 191.22 by adding paragraph (c)(2)(vi) to read as follows:

§ 191.22 National Registry of Operators.

* * * * *

(c) * * *

(2) * * *

(vi) A change in the classification of a pipeline segment from a Class 1 to a Class 3 location where the operator chooses to confirm or revise the maximum allowable operating pressure (MAOP) in accordance with § 192.611(a)(4) of this chapter. The notification must include the following information about the Class 1 to Class 3 location segment: State, county, pipeline name or number, pipe diameter, MAOP, wall thickness, pipe grade/strength, seam type, Class 1 to Class 3 location change date, segment length, pipeline location by both GIS coordinates and pipeline system survey stations or mile posts for the starting and ending points of the Class 1 to Class 3 location segment, and the date of the Class 1 to Class 3 location change.

* * * * *

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 3. The authority citation for part 192 is revised to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.,* and 49 CFR 1.97.

■ 4. Amend § 192.3 by adding the definitions of ''Class 1 to Class 3 location segment'', ''In-line inspection segment'', and ''Predicted failure pressure'' in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Class 1 to Class 3 location segment means a pipeline segment where:

(1) The segment has changed from a Class 1 to a Class 3 location; and

(2) The operator is confirming or revising the maximum allowable operating pressure per § 192.611(a)(4). At the operator's discretion, the endpoints of the Class 1 to Class 3 location segment may extend further than the beginning and endpoints of the Class 3 location involved.

* * * * *

In-line inspection segment means all pipe within a Class 1 to Class 3 location segment and all pipe adjacent to the Class 1 to Class 3 location segment between the nearest upstream in-line inspection launcher and the nearest downstream in-line inspection receiver.

* * * * *

Predicted failure pressure means the calculated pipeline anomaly failure pressure, based on the use of an appropriate engineering evaluation method for the type of anomaly being assessed, that does not have an included safety factor. Different anomaly types (*e.g.,* dent, crack, or metal loss) will require different engineering assessment or analysis methods to determine the predicted failure pressure.

* * * * *

■ 5. Amend § 192.7 by revising paragraphs (b)(12) and (c)(6) to read as follows:

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

* * * * *

(b) * * *

(12) API STANDARD 1163, ''In-Line Inspection Systems Qualification,'' Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for §§ 192.493, 192.618(b)(4), and (b)(4)(iii).

* * * * *

(c) * * *

(6) ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines,'' 2004, (ASME/ANSI B31.8S–2004), IBR approved for §§ 192.618; 192.903 note to *Potential impact radius*; 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (*l*), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a).

■ 6. Amend § 192.611 by adding paragraph (a)(4) and revising paragraph (d) to read as follows:

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) * * *

(4) A Class 1 to Class 3 location segment may have its maximum allowable operating pressure confirmed or revised in accordance with § 192.618.

* * * * *

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section or implementing an integrity assessment program that meets paragraph (a)(4) of this section at a later date. The activities required in paragraphs (a)(3) or (4) of this section must be implemented prior to any future increases of maximum allowable operating pressure to meet paragraphs (a)(1) or (2) of this section.

■ 7. Add § 192.618 to read as follows:

§ 192.618 Class 1 to Class 3 location segment requirements.

A Class 1 to Class 3 location segment must meet the following requirements:

(a) *Program requirements for a Class 1 to Class 3 location segment.* For segments that change from a Class 1 to a Class 3 location, the maximum allowable operating pressure (MAOP) must be confirmed or revised by designating the segment involved as a high consequence area, as defined in § 192.903, and including it in an integrity management program in accordance with subpart O of this part, if the following criteria are met:

(1) *Timing of Class 1 to Class 3 location change.* The Class 1 to Class 3 location segment change must have occurred after [INSERT EFFECTIVE DATE OF FINAL RULE]. An operator must conduct a class location study on the in-line inspection segment at least once each calendar year, with intervals not to exceed 15 months, in accordance with § 192.609. An operator must maintain its in-line inspection segment change in class location study records in accordance with paragraph (h) of this section.

(2) *In-line inspection.* The in-line inspection segment must be assessed using instrumented in-line inspection tools that meet the requirements of paragraph (b)(1) of this section.

(3) *Hoop stress of Class 1 to Class 3 location segment.* The hoop stress corresponding to the MAOP of the Class 1 to Class 3 location segment must not exceed 72 percent of SMYS in Class 3 locations.

(4) *Pipe attributes for review.* Pipeline segments with any of the following attributes cannot be a Class 1 to Class 3 location segment:

(i) Bare pipe;

(ii) Pipe with wrinkle bends;

(iii) Pipe that does not have traceable, verifiable, and complete pipe material records for diameter, wall thickness, grade, seam type, yield strength, and tensile strength;

(iv) Pipe that is uprated in accordance with subpart K (unless the segment passes a subpart J pressure test for a minimum of 8 hours at a minimum pressure of 1.39 times MAOP within 24 months after the Class 1 to Class 3 location segment change and prior to uprating or increasing the current MAOP);

(v) Pipe that has not been pressure tested in accordance with subpart J for 8 hours at a minimum test pressure of 1.25 times MAOP (unless the segment passes a subpart J pressure test for a minimum of 8 hours at a minimum pressure of 1.25 times MAOP within 24 months after the Class 1 to Class 3 location segment change);

(vi) Pipe with direct current (DC), low frequency electric resistance welded (LF–ERW), electric flash welded (EFW), or lap-welded seams, or pipe with a longitudinal joint factor below 1.0; or

(vii) Pipe with cracking in the pipe body, seam, or girth welds in or within 5 miles of the Class 1 to Class 3 location segment that is over 20 percent of the pipe wall thickness, has a predicted failure pressure less than 100 percent of SMYS, has a predicted failure pressure less than 1.50 times MAOP, has experienced a leak or a rupture due to pipe cracking, or for which analysis in accordance with paragraph (e) of this section indicates the pipe could fail in brittle mode.

(viii) Poor pipe external coating that requires a minimum negative cathodic polarization voltage shift of 100 millivolts or linear anodes along the Class 1 to Class 3 location segment to maintain cathodic protection in accordance with § 192.463, or a Class 1 to Class 3 location segment with tape wraps or shrink sleeves.

(ix) Pipe that transports gas whose composition quality is not suitable for sale to gas distribution customers, including, but not limited to, pipe with free-flowing water or hydrocarbons, water vapor content exceeding acceptable limits for gas distribution customer delivery, hydrogen sulfide (H_2S) greater than one grain per 100 cubic feet, or carbon dioxide (CO_2) greater than 3 percent by volume.

(x) Pipelines operating in accordance with § 192.619(c) or (d).

(xi) A Class 1 to Class 3 location segment, in-line inspection segment, or portion of it that has been previously denied by the special permit process in § 190.341.

(b) *Pipeline integrity assessments.* In addition to the requirements specified in subpart O of this part, pipeline integrity assessments for the in-line inspection segment, including the Class 1 to Class 3 location segment, must meet the following:

(1) *Assessment method.* Operators must perform pipeline assessments using the following in-line inspection tools or alternative methods as applicable for the pipeline integrity threats being assessed:

(i) In-line inspection with a high-resolution magnetic flux leakage (HR–MFL) tool or an equivalent internal inspection device;

(ii) In-line inspection with a high-resolution deformation tool (HR-Deformation), with sensors and extension arms outside the tool cups, or an equivalent internal inspection device;

(iii) In-line inspection with an electromagnetic acoustic transducer (EMAT) tool or an equivalent internal inspection device;

(iv) In-line inspection with an inertial measurement unit (IMU) tool or an equivalent internal inspection device;

(v) An operator may use alternative methods, such as pressure testing or other technology (excluding direct assessment), upon submitting a notification to PHMSA 90 days prior to using the alternative method, in accordance with § 192.18.

(vi) If an operator chooses not to conduct the in-line inspection as required in paragraphs (iii) or (iv) on a pipeline segment with a history of pipe body or weld cracking or pipe movement, then the operator must notify PHMSA in accordance with § 192.18.

(2) *Initial assessment.* Within 24 months of the Class 1 to Class 3 location segment change, an operator must identify and document each integrity threat to which the pipeline segment is susceptible and conduct initial pipeline integrity assessments of the entire in-line inspection segment for each threat in accordance with §§ 192.917, 192.921, and paragraph (b)(1) of this section.

(3) *Reassessments.* The operator must conduct periodic reassessments in accordance with § 192.937 and paragraph (b)(1) of this section at least once every 7 calendar years, with intervals not to exceed 90 months, as specified in § 192.939(a).

(4) *In-line Inspection Validation.* Operators must validate the results of all in-line inspections, for each type in-line inspection tool run conducted in accordance with this section, to Level 3 standards in accordance with API Standard 1163 (incorporated by reference, *see* § 192.7).

(i) An operator must analyze and account for uncertainties in reported results (*e.g.,* tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) when identifying and characterizing anomalies.

(ii) For each threat type assessed by ILI tool type, an operator must validate the in-line inspection tool tolerance for each in-line inspection tool run using a minimum of 4 anomaly validations or 100 percent of anomalies, whichever is less, either from new excavations or from past excavations in the in-line inspection segment, with documented anomaly dimensions (width, depth, length, and location) or other known pipe features that are appropriate for the in-line inspection tool.

(iii) For pipeline areas of metal loss where in-line inspection tool data for anomaly size and characterization are used in the determination of the predicted anomaly failure pressure, an operator must use Section 6.2.3, Table 1—Characterizing Metal Loss Probabilities of Detection—Depth Detection Threshold, in accordance with API Standard 1163 (incorporated by reference, *see* § 192.7). Using the qualifiers and limitation criteria in Section 6.2.3, Table 1 of API Standard 1163 or technically proven criteria appropriate for the location, size, and type of the anomaly, an operator must evaluate the anomaly based on whether it is an extended metal loss, pit, or groove.

(iv) An operator may use alternative methods for in-line inspection tool verification, such as calibration joints near the upstream and downstream ILI tool launchers and receivers, upon submitting a notification to PHMSA 90 days prior to using the alternative method, in accordance with § 192.18.

(5) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under § 192.933 and paragraphs (c), (d), and (e) of this section. An operator must promptly, but no later than 180 days after conducting a pipeline integrity assessment, obtain sufficient information about a condition to make such a determination of an integrity threat that requires remediation.

(c) *Remediation schedule (In-line inspection segment).* In addition to the requirements specified in subpart O of this part, remediation for the in-line inspection segment, including the Class 1 to Class 3 location segment, must meet the following:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) Metal loss anomalies where the calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) Metal loss greater than 80 percent of nominal wall, regardless of dimensions.

(iii) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is less than or equal to 1.25 times the MAOP.

(iv) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless a technically proven engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) *One-year conditions.* An operator must repair the following conditions within 1 year of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b), at the location of the anomaly less than or equal to 1.39 times the MAOP for Class 2 locations, and 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations outside the Class 1 to Class 3 location segment with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, figure 4. For Class 1 pipe within the Class 1 to Class 3 location segment, a metal loss anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, with a predicted failure pressure determined in accordance with § 192.712(b) less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(vi) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(vii) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with § 192.712(d) that is less than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, a crack or crack-like anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(3) *Remediation schedule (Class 1 to Class 3 location segment).* In addition to the requirements in paragraph (e) of this section, remediation for the Class 1 to Class 3 location segment must meet the following:

(i) *One-year condition.* An operator must repair the following conditions within 1 year of discovery:

(A) Pipe wall thickness loss greater than 40 percent.

(B) A crack with depth greater than 40 percent of the pipe wall thickness.

(ii) [Reserved].

(4) *Two-year condition for crack repairs (in-line inspection segment).* An operator must repair the following condition within 2 years of discovery:

(i) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with § 192.712(d) that is greater than or equal to 1.39 times MAOP, and the crack depth is greater than or equal to 40 percent of the pipe wall thickness.

(ii) [Reserved].

(5) *Monitored condition.* An operator does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment interval, provided an analysis shows they are not expected to grow to dimensions meeting a 1-year condition prior to the next scheduled assessment. Monitored conditions are:

(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe);

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and an engineering analysis conducted in accordance with § 192.712(c) demonstrate that critical strain levels on the dent will not be exceeded;

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels on the dent and girth or seam weld will not be exceeded;

(iv) A dent that has metal loss, cracking, or a stress riser, and an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded;

(v) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is greater than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP; and

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, a crack or crack-like anomaly with a predicted failure pressure greater than 1.39 times the MAOP.

(d) *Special requirements for crack anomalies.* If cracks are discovered in the Class 1 to Class 3 location segment that meet the criteria in paragraph (a)(4)(vii) of this section, the operator must implement the requirements in § 192.611(a)(1), (2), or (3) within 2 years. Until the pipe is replaced, operators must remediate cracks as specified in paragraph (c) of this section.

(e) *Pipe and weld cracking inspections.* Except for pipe coated with fusion-bonded or liquid-applied epoxy coatings and excavations performed in accordance with § 192.614(c), an operator must inspect any pipe in the in-line inspection segment, including the Class 1 to Class 3 location segment, that is uncovered for any reason to evaluate the pipe for cracking where the coating is removed. An operator must use non-destructive examination methods and procedures appropriate for the type of non-destructive examination method, and for the type of pipe and integrity threat conditions in the ditch. If an operator finds any cracking, the operator must conduct an analysis in accordance with § 192.712 and remediate anomalies in accordance with paragraphs (c) and (d) of this section.

(f) *Additional preventive and mitigative measures.* For a Class 1 to Class 3 location segment, an operator must conduct the following operations and maintenance actions and surveys within 2 years of the Class 1 to Class 3 location segment change, evaluate the findings, and remediate as follows:

(1) Close interval surveys with an ''on and off'' current at a maximum 5-foot spacing. An operator must evaluate in accordance with § 192.463 and remediate the unprotected pipe segments within 1 year of the survey. Operators must conduct close interval surveys on reassessment intervals of at least once every 7 calendar years, with intervals not to exceed 90 months.

(2) At least 1 cathodic protection pipe-to-soil test station must be located within the Class 1 to Class 3 location segment with a maximum spacing of ½ mile between test stations. In cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. Annual monitoring of the cathodic protection pipe-to-soil test stations must meet §§ 192.463 and 192.465 for the Class 1 to Class 3 location segment.

(3) Install and maintain line-of-sight markers visible on the pipeline right-of-way, except in agricultural areas or large water crossings, such as lakes, where line-of-sight markers are not practical. An operator must replace line-of-sight markers as necessary and within 30 days after identifying a missing line-of-sight marker.

(4) Interference surveys to address induced alternating current (AC) from parallel electric transmission lines, and other interference issues, such as direct current (DC), that may affect the Class 1 to Class 3 location segment. If an interference survey finds the interference current is greater than or equal to 100 amps per meter squared, impedes the safe operation of a pipeline, or may cause a condition that would adversely impact the environment or public safety, an operator must correct these instances within 15 months of the interference survey.

(5) Depth of cover must conform with § 192.327 for a Class 1 to Class 3 location segment or be remediated by adding markers at locations that do not meet the requirements of § 192.327 for a Class 1 location, lowering the pipe, adding cover, or installing safety barriers. Where the depth of cover is less than 24 inches in areas of non-consolidated rock, the operator must either lower the pipe or add cover over the Class 1 to Class 3 location segment.

(6) Right-of-way patrols in accordance with paragraphs (a) and (c) of § 192.705 at least once per month, with intervals not to exceed 45 days for Class 1 to Class 3 location segments.

(7) Leakage surveys at intervals not exceeding 4½ months, but at least four times each calendar year for Class 1 to Class 3 location segments.

(8) For shorted casings in Class 1 to Class 3 location segments, operators must clear the metallic short no later than 1 year after the short is identified. For an electrolytic casing short, operators must remove the electrolyte from the casing/pipe annular space no later than 1 year after the short is identified.

(g) *Remote-control or automatic shutoff valves.* Mainline valves on both sides of Class 1 to Class 3 location segments, and isolation valves on any crossover or lateral pipe designed to isolate a leak or rupture in a Class 1 to Class 3 location segment, must be operational remote-controlled or automatic shutoff valves with pressure sensors on each side of the mainline valves. The maximum distance between such mainline valves must not exceed 20 miles.

(1) Valves installed in accordance with this paragraph must be closed as soon as practicable after a rupture is identified, but not to exceed 30 minutes.

(2) Valves installed in accordance with this paragraph must be operational at all times, controlled by a SCADA system, and monitored in accordance with § 192.631.

(3) Valves installed in accordance with this paragraph must be maintained in accordance with §§ 192.631(c)(2) and (c)(3), and 192.745.

(4) Automatic shutoff valves installed in accordance with this paragraph must be set so that, based on operating conditions and minimum and maximum flow model gradients, they will fully close within a maximum of 30 minutes following rupture identification. Automatic shutoff valve set-points must not be less than those required to actuate the valve before a downstream remote-control valve actuates. The automatic shutoff valve procedure and results for determining shutoff times must be reviewed for accuracy at least once each calendar year, with intervals not to exceed 15 months.

(h) *Documentation.* In addition to the documentation requirements specified in § 192.947, each operator must maintain records of all actions implemented to comply with paragraph (e) of this section for the life of the pipeline, including but not limited to subpart J pressure test records in accordance with § 192.517; and records of any pipeline assessments, surveys, remediations, maintenance, analyses, and other implemented actions.

(i) *Notifications to PHMSA of integrity assessment program for class 1 to class 3 location segment changes.* Each operator of a gas transmission pipeline that uses the integrity assessment program option for managing a Class 1 to Class 3 location segment change must notify PHMSA electronically in accordance with § 191.22(c)(2).

■ 8. Amend § 192.712 by revising the section heading and adding paragraph (c) to read as follows:

§ 192.712 Analysis of predicted failure pressure and critical strain level.

* * * * *

(c) *Dents.* To evaluate dents and other mechanical damage that could result in a stress riser, an operator must perform an engineering critical assessment, as follows:

(1) Evaluate potential threats for the pipe segment in the vicinity of the anomaly or defect including movement, external loading, cracking, and corrosion;

(2) Review high-resolution magnetic flux leakage (HR–MFL) and high-resolution deformation inline inspection data for damage in the dent area and any associated weld region;

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data;

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape;

(5) Identify and quantify all significant loads acting on the dent;

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or another technology in accordance with paragraph (c)(8) of this section;

(7) The analyses performed in accordance with this section must account for material property uncertainties and model inaccuracies and tolerances;

(8) Dents with geometric strain levels that exceed the critical strain must be remediated in accordance with § 192.713 or § 192.933, as applicable;

(9) Using operational pressure data, a valid fatigue life prediction model, and assuming a reassessment safety factor of 2, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique in accordance with this section;

(10) An operator using other technologies or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA in accordance with § 192.18.

■ 9. In § 192.903, amend the definition of *high consequence area* by revising paragraphs (1) and (2) to read as follows:

§ 192.903 What definitions apply to this subpart?

* * * * *

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site; or

(v) Any Class 1 to Class 3 location segment designated as a high consequence area in accordance with § 192.618(a).

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site; or

(iii) Any Class 1 to Class 3 location segment designated as a high consequence area in accordance with § 192.618(a).

* * * * *

Issued in Washington, DC, on September 3, 2020, under authority delegated in 49 CFR 1.97.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

[FR Doc. 2020–19872 Filed 10–13–20; 8:45 am]

BILLING CODE 4910–60–P