

set points for the supervisory control and data acquisition system.

[73 FR 62177, Oct. 17, 2008, as amended by Amdt. 192-111, 74 FR 62505, Nov. 30, 2009; Amdt. 192-120, 80 FR 12779, Mar. 11, 2015]

§ 192.621 Maximum allowable operating pressure: High-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.

(2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of § 192.197(c).

(3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.623 Maximum and minimum allowable operating pressure; Low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure

lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

(a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

(1) Records necessary to establish the MAOP in accordance with § 192.619(a), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A Class 3 or Class 4 location.

(2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A Class 3 or Class 4 location; or

(iii) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

(b) *Procedures and completion dates.* Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:

(1) Operators must complete all actions required by this section on at

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least 50% of the pipeline mileage by July 3, 2028.

(2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (e.g., due to a location becoming a high consequence area), whichever is later.

(3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:

(1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:

(i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii).

(ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

(iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If

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there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*i.e.*, the location-specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

(A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

(B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.

(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.

(iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with §192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in §192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with §192.712;

(C) Justification that establishing MAOP by another method allowed by this section is impractical;

(D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance §192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(E) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue

growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

(3) *Method 3: Engineering Critical Assessment (ECA).* Conduct an ECA in accordance with §192.632.

(4) *Method 4: Pipe Replacement.* Replace the pipeline segment in accordance with this part.

(5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius.* Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:

(i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.*, the location specific operating pressure at each location);

(ii) Conduct patrols in accordance with §192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with §192.706 at intervals not to exceed those in the following table 1 to §192.624(c)(5)(ii):

TABLE 1 TO § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2 ..	3½ months, but at least four times each calendar year.	3½ months, but at least four times each calendar year.
(B) Class 3 and Class 4 ..	3 months, but at least six times each calendar year.	3 months, but at least six times each calendar year.

(iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

(6) *Method 6: Alternative Technology.* Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with §192.18.

The notification must include descriptions of the following details:

(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required

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corresponding hydrostatic test pressure for the pipeline segment being evaluated;

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712;

(vi) Operational monitoring procedures;

(vii) Methodology and criteria used to justify and establish the MAOP; and

(viii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.

(d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

[84 FR 52247, Oct. 1, 2019]

EFFECTIVE DATE NOTE: At 84 FR 52247, Oct. 1, 2019, § 192.624 was added, effective July 1, 2020.

§ 192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

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(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by—