Operations & Maintenance Enforcement Guidance

Part 195 Subpart F

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Introduction

The materials contained in this document consist of guidance, techniques, procedures and other information for internal use by the PHMSA pipeline safety enforcement staff. This guidance document describes the practices used by PHMSA pipeline safety investigators and other enforcement personnel in undertaking their compliance, inspection, and enforcement activities. This document is U.S. Government property and is to be used in conjunction with official duties.

The Federal pipeline safety regulations (49 CFR Parts 190-199) discussed in this guidance document contains legally binding requirements. This document is not a regulation and creates no new legal obligations. The regulation is controlling. The materials in this document are explanatory in nature and reflect PHMSA's current application of the regulations in effect at the time of the issuance of the guidance. In preparing an enforcement action alleging a probable violation, an allegation must always be based on the failure to take a required action (or taking a prohibited action) that is set forth directly in the language of the regulation. An allegation should never be drafted in a manner that says the operator "violated the guidance."

Nothing in this guidance document is intended to diminish or otherwise affect the authority of PHMSA to carry out its statutory, regulatory or other official functions or to commit PHMSA to taking any action that is subject to its discretion. Nothing in this document is intended to and does not create any legal or equitable right or benefit, substantive or procedural, enforceable at law by any person or organization against PHMSA, its personnel, State agencies or officers carrying out programs authorized under Federal law.

Decisions about specific investigations and enforcement cases are made according to the specific facts and circumstances at hand. Investigations and compliance determinations often require careful legal and technical analysis of complicated issues. Although this guidance document serves as a reference for the staff responsible for investigations and enforcement, no set of procedures or policies can replace the need for active and ongoing consultation with supervisors and colleagues in enforcement matters.

Comments and suggestions for future changes and additions to this guidance document are invited and should be forwarded to your supervisor.

The materials in this guidance document may be modified or revoked without prior notice by PHMSA management.

Glossary

For a complete “Glossary of Terms” please refer to the following link:

http://www.phmsa.dot.gov/staticfiles/PHMSA/Pipeline/TQGlossary/Glossary.html

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.401
Section Title	General Requirements
Existing Code Language	(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under §195.402(a) of this subpart. (b) An operator must make repairs on its pipeline system according to the following requirements: (1) Non Integrity management repairs. Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition. (2) Integrity management repairs. When an operator discovers a condition on a pipeline covered under § 195.452, the operator must correct the condition as prescribed in § 195.452(h). (c) Except as provided by §195.5, no operator may operate any part of any of the following pipelines unless it was designed and constructed as required by this part: (1) An interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid. (2) An interstate offshore gathering line, other than a low-stress, on which construction was begun after July 31, 1977, that transports hazardous liquid. (3) An intrastate pipeline, other than a low-stress pipeline, on which construction was begun after October 20, 1985, that transports hazardous liquid. (4) A pipeline, on which construction was begun after July 11, 1991 that transports carbon dioxide. (5) A low-stress pipeline on which construction was begun after August 10, 1994.
Origin of Code	Original Code Document, 44 FR 41197, 07-16-1979
Last Amendment	Amdt. 195-94, 75 FR 48593, 08-11-2010
Interpretation Summaries	**Interpretation: PI-84-0103 Date: 08-06-1984** The Department does have maintenance standards for gas and hazardous liquid pipelines (49 CFR Part 192, Subpart M, and Part 195, Subpart F). Although these maintenance standards do not require that any particular amount of cover be maintained, if an operator knows or should know that a pipeline has become unsafe because of inadequate cover, the standards require that appropriate remedial action be taken (49 CFR 192.703 and 195.401). Proper cover over a buried pipeline is an important safety feature, because it distributes external loads and provides stability for the pipeline. Thus, the

	Department's standards for constructing new pipelines require adequate cover over buried pipelines (49 CFR 192.327 and 195.248). However, once installed, cover is costly and difficult to maintain, because of erosion and other surface altering activities. Moreover, the Department's pipeline accident data do not show any significant correlation between depth of cover and prevention of accidents due to digging. Although it seems reasonable to expect that adequate cover would reduce these types of accidents, there is not any evidence to support the proposition that maintaining original cover would be cost-effective as a general safety rule. **Interpretation: PI-83-0104- Date: 04-13-1983** The following responds to whether the pipeline company has a duty to test the pipe. The applicable regulations for interstate oil pipelines in effect at the time of the accident (49 CFR Part 195) require that after March 31, 1970, new, relocated, or replaced pipe be hydrostatically tested (§§195.300 and 195.401(c)). However, this requirement may not apply to the pipe involved in the accident because the accident report indicates the pipeline was constructed circa 1920. **Interpretation: PI-78-028 Date: 08-10-1979** (Interpretation refers to 195.402; however, the sections referenced are now in 195.401) In the design of the pipeline, Alyeska developed stress criteria that took into account all credible live and dead loads and occasional loads (such as earthquakes) to which the pipeline could be subjected. To provide an acceptable level of safety under these criteria, when the buried pipe is subject to design contingency loadings (design contingency earthquake and/or settlement), the highest allowable stress established for the buried pipe was 1.15 SMYS. These design loads were exceeded in the buckled area. Continuing to operate the buckled section of the pipeline would not be in accordance with §195.402(b) (195.401(a)) because the deformation that has occurred materially altered the mechanical properties of the pipe, weakening it which would thereby provide a level of safety lower than that required by this subpart and the allowable stress established by Alyeska. Because the deformed pipeline could adversely affect the safe operation of the pipeline system, §195.402(b) (195.401(b)) requires that the condition must be corrected within a reasonable time.

Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-2015-02, Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes** All owners and operators of gas and hazardous liquid pipelines are reminded that pipeline safety problems can occur from the passage of hurricanes. Pipeline operators are urged to take the following actions to ensure pipeline safety: 1. Identify persons who normally engage in shallow-water commercial fishing, shrimping, and other marine vessel operations and caution them that underwater offshore pipelines may be exposed or constitute a hazard to navigation. Marine vessels operating in water depths comparable to a vessel's draft or when operating bottom dragging equipment can be damaged and their crews endangered by an encounter with an underwater pipeline. 2. Identify and caution marine vessel operators in offshore shipping lanes and other offshore areas that deploying fishing nets or anchors and conducting dredging operations may damage underwater pipelines, their vessels, and endanger their crews. 3. After a disruption, operators need to bring offshore and inland transmission facilities back online, check for structural damage to piping, valves, emergency shutdown systems, risers and supporting systems. Aerial inspections of pipeline routes should be conducted to check for leaks in the transmission systems. In areas where floating and jack-up rigs have moved and their path could have been over the pipelines, review possible routes and check for sub-sea pipeline damage where required. **Advisory Bulletin ADB-11-04, Potential for damage to pipeline facilities caused by severe flooding.** Severe flooding can adversely affect the safe operation of a pipeline. Operators need to direct their resources in a manner that will enable them to determine the potential effects of flooding on their pipeline systems. Operators are urged to take the following actions to prevent and mitigate damage to pipeline facilities and ensure public and environmental safety in areas affected by flooding: 1. Evaluate the accessibility of pipeline facilities that may be in jeopardy, such as valve settings, which are needed to isolate water crossings or other sections of a pipeline. 2. Extend regulator vents and relief stacks above the level of anticipated flooding, as appropriate. 3. Coordinate with emergency and spill responders on pipeline location and condition. Provide maps and other relevant information to such responders. 4. Coordinate with other pipeline operators in the flood area and establish emergency response centers to act as a liaison for pipeline problems and solutions.

5. Deploy personnel so that they will be in position to take emergency actions, such as shut down, isolation, or containment.

6. Determine if facilities that are normally above ground (e.g., valves, regulators, relief sets, etc.) have become submerged and are in danger of being struck by vessels or debris; if possible, such facilities should be marked with an appropriate buoy with Coast Guard approval.

7. Perform frequent patrols, including appropriate patrols to evaluate right-of-way conditions at water crossings during flooding and after waters subside. Determine if flooding has exposed or undermined pipelines as a result of new river channels cut by the flooding or by erosion or scouring.

8. Perform surveys to determine the depth of cover over pipelines and the condition of any exposed pipelines, such as those crossing scour holes. Where appropriate, surveys of underwater pipe should include the use of visual inspection by divers or instrumented detection. Information gathered by these surveys should be shared with affected landowners. Agricultural agencies may help to inform farmers of the potential hazard from reduced cover over pipelines.

9. Ensure that line markers are still in place or replaced in a timely manner. Notify contractors, highway departments, and others involved in post-flood restoration activities of the presence of pipelines and the risks posed by reduced cover.

If a pipeline has suffered damage, is shut-in, or is being operated at a reduced pressure as a precautionary measure as a result of flooding, the operator should advise the appropriate PHMSA Regional Office or State pipeline safety authority before returning the line to service, increasing its operating pressure, or otherwise changing its operating status. PHMSA or the State will review all available information and advise the operator, on a case-by-case basis, whether and to what extent a line can safely be returned to full service.

Advisory Bulletin ADB -99-03, Potential Service interruption in SCADA Systems.

Each pipeline operator should review the capacity of its SCADA system to ensure that the system has resources to accommodate normal and abnormal operations on its pipeline system. In addition, SCADA configuration and operating parameters should be periodically reviewed, and adjusted if necessary, to assure that the SCADA computers are functioning as intended. Further, operators should assure system modifications do not adversely affect overall performance of the SCADA system. We recommend that the operator consult with the original system designer.

Advisory Bulletin ADB-94-05, Areas that may be subject to severe flooding.

This advisory is for all operators of pipelines which may be affected by flooding. It provides observations from RSPA, Texas Railroad Commission (TRC), and other federal and state agencies as a result of the recent floods near Houston. This advisory also includes actions that operators should consider taking to assure the integrity of pipelines in case of flooding.

	As the result of unprecedented flooding of rivers and streams in the Houston area, seven natural gas and hazardous liquid pipelines failed in or near the San Jacinto River over the three-day period October 19-21, 1994. These failures included: an Exxon 8-inch diameter LPG line; an Exxon 8-inch diameter fuel line; an Exxon 20-inch diameter hazardous liquid line; a Colonial 40-inch diameter products (gasoline) line; a Colonial 36-inch diameter products (heating oil) line; a Texaco 20-inch diameter crude oil line; and a Valero 12-inch diameter natural gas line. While no determination of cause of failure has been made for any of these lines, RSPA and the TRC believe that the extreme flooding by the San Jacinto River was probably a substantial contributing factor in each of the failures. The damage to pipelines caused by the flood may have resulted either from the extreme force of the flowing water, as the San Jacinto carved new temporary channels, or from pipelines being struck by heavy debris that was reported as having flowed down river at the height of the flooding. Because RSPA and the TRC cannot at this time determine the exact effects of the flooding, operators should consider the potential effects of flooding as posing a possible threat to the integrity of their lines. **Alert Notice ALN-90-01, Advise offshore water operators of recurring safety problem involving marine vessel operations and crew safety.** The purpose of this Alert Notice is to advise all operators of natural gas and hazardous liquid pipelines located in offshore waters of recurring safety problems involving marine vessel operations and to alert you that exposed pipelines pose a threat to the safety of the crews of fishing vessels in shallow coastal waters and to other marine operations in shipping lanes and deeper offshore waters. The Notice reminds operators of offshore pipelines of the requirements of federal agencies regarding the safety of pipelines. The Notice is sent to all pipeline operators to alert them of similar problems that may occur in inland navigable waterways. Also, OPS is alerting the commercial fishing industry of the potential of unburied offshore pipelines by sending this Notice to Louisiana Shrimp Association, Texas Shrimp Association, Southeastern Fisheries Association, National Fish Meal & Oil Association, and Concerned Shrimpers of America. Pipeline operators or mariners aware of any portion of a submerged pipeline should report that information to the appropriate US Coast Guard District. OPS pipeline regulations require operators to patrol their lines periodically for the presence of unusual operating and maintenance conditions and to take corrective action if conditions are unsafe. Because this patrolling is generally done using aircraft, pipelines exposed on the seafloor cannot be visually detected. It is likely that some pipelines located in shallow waters are exposed or have inadequate cover. It is important to note that if a pipeline operator has knowledge that its pipeline is exposed in areas where shallow water fishing operations are conducted, sections 192.613 and 192.703 applicable to gas pipeline operators, and section 195.401 applicable to hazardous liquid pipeline operators would require the operator to take steps to remove the danger.
Other Reference Material	

& Source	
Guidance Information	1. Operators are expected to identify, evaluate and react to potentially adverse conditions. 2. Paragraph (a) is usually coupled with other regulations during enforcement actions. 3. Enforcement should be sought when the investigator is convinced that corrective action was unreasonably delayed. 4. Examples of conditions which require evaluation to determine if they are unsafe include, but are not limited to: a. washouts b. exposed spanning pipe c. mud-slides & landslides d. ice-balls e. snow accumulations f. unprotected facilities from reasonably anticipated on-road and off-road vehicular damage g. debris buildup on river/stream crossings that is detrimental to the pipe 5. The operator must evaluate any loss of cover to determine if an unsafe condition exists. When the operator becomes aware of an unsafe condition, it must take appropriate action to prevent damage in a reasonable time. Such action may be other than restored cover. 6. In the event of an immediate hazard not alleviated by a reduction in operating pressure, the operator must shutdown the pipeline until the condition is corrected.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not correct an adverse condition within a reasonable time. 2. The operator continued to operate a pipeline that presented an immediate hazard to persons or property. 3. Pipeline has been operated and it does not comply with design & construction requirements after the dates of applicability. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Documentation that an adverse condition was not corrected within a reasonable time. 2. Documentation that an immediate hazard to persons or property existed. 3. Operator's records showing dates of discovery and remediation. 4. Documented statements from Operator- Public complaint reports. 5. Photographs.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.402(a)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies
Existing Code Language	(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to ensure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.
Origin of Code	Original Code Document, 69 FR 11911, 10-04-1969
Last Amendment	Amdt. 195-69, 65 FR 54440, 09-08-2000
Interpretation Summaries	**Interpretation: PI- 83-0101 Date: 01-26-1983** Pipeline operators should have procedures for operating launchers and receivers to safely relieve pressure in the barrel before insertion or removal of scrapers, spheres or pigs.
Advisory Bulletins/Alert Notice Summaries	**Advisory Bulletin ADB-10-06, Personal Electronic Device (PED) Related Distractions.** As with other modes of transportation, PHMSA recognizes the use of PEDs by pipeline employees who are performing operations and maintenance activities may increase safety risks if those individuals become distracted. In furtherance of the Department's effort to end the dangerous practice of distractions caused by PEDs throughout the various modes of transportation, PHMSA is issuing this Advisory Bulletin about the potential for distractions affecting pipeline safety. PHMSA reminds owners and operators of natural gas and hazardous liquid pipeline facilities that there may be increased risks associated with the use of PEDs by individuals performing activities that affect pipeline operation or integrity. Pipeline operations and maintenance tasks require a critical level of attention and skill, which may be compromised by visual, manual, and cognitive distractions caused by the use of PEDs. Such distractions may also hinder their prompt recognition and reaction to abnormal operating conditions and emergencies. Owners and operators of natural gas and hazardous liquid pipeline facilities should integrate into their written procedures for operations and maintenance appropriate controls regarding the personal use of PEDs by individuals performing pipeline tasks that may affect the operation or integrity of a pipeline. PHMSA is not discouraging the use of PEDs as a part of normal business operations. Owners and operators should also provide guidance and training for all personnel about the risks associated

	with the use of PEDs while driving and while performing activities on behalf of the company if that use poses a risk to safety. 2. Operators should ensure the record it maintains of its annual O&M review, as required by §§ 192.605(a) and 195.402(a), specifically notes that the OQ Plan was included in the review. The record should include the name of reviewer and date(s) of review. Alternatively, the operator's review procedures may clearly indicate which procedures are to be evaluated during the annual review.
Other Reference Material & Source	
Guidance Information	1. The operator's O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual. 2. It is permissible to have on-line access to an electronic copy of the O&M Plan; however, appropriate portions of the plan must be readily accessible locally, even if network connectivity to headquarters is temporarily not available. The same is true for maps showing the location of emergency valves and other pertinent information. 3. Procedures are required for functions and facilities in a system. 4. Procedures are not just for the field personnel. 5. Procedures are required for tasks normally performed by engineering, the operations control center, and other headquarters-type functions as applicable to O&M tasks. 6. The procedures should be clear, straight forward, and applicable to the company's system. 7. The procedure must be written prior to the operation or maintenance activity. 8. Operator review is required every Calendar year. 9. Who did it and when.
Examples of a Probable Violation or Inadequate Procedures	1. Procedures were not prepared prior to operation. 2. Written procedures have not been followed. 3. Written procedures not reviewed and updated at required intervals. 4. Current updated procedure is not available or personnel are using an outdated version. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Observation and/or photographs that indicate written procedures are not being followed. 2. Operator's records and statements. 3. Copy of O&M plan or applicable portion that shows omission or deficiency in the plan. 4. Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.402(b)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies
Existing Code Language	(b) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.
Origin of Code	Original Code Document, 69 FR 11911, 10-04-1969
Last Amendment	Amdt. 195-55, 61 FR 18512, 04-26-1996
Interpretation Summaries	
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Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.402(c)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies
Existing Code Language	(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations: (1) Making construction records, maps, and operating history available as necessary for safe operation and maintenance. (2) Gathering of data needed for reporting accidents under Subpart B of this part in a timely and effective manner. (3) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart H of this part. (4) Determining which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned. (5) Analyzing pipeline accidents to determine their causes. (6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section. (7) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the limits prescribed by paragraph §195.406, consider the hazardous liquid or carbon dioxide in transportation, variations in altitude along the pipeline, and pressure monitoring and control devices. (8) In the case of pipeline that is not equipped to fail safe, monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by §195.406. (9) In the case of facilities not equipped to fail safe that are identified under §195.402(c)(4) or that control receipt and delivery of the hazardous liquid or carbon dioxide, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location. (10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with §195.59 of this part. (11) Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases. (12) Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each government organization that may respond to a hazardous liquid or pipeline emergency and

	acquaint the officials with the operator's ability in responding to a hazardous liquid or carbon dioxide pipeline emergency and means of communication. (13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found. (14) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line. (15) Implementing the applicable control room management procedures required of §195.446.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-93, 74 FR 63310, 12-03-2009
Interpretation Summaries	**Interpretation: PI-09-0005** Date: **April 6, 2009** PHMSA regulations do not recognize an "idle" status for a hazardous liquid pipeline. should be aware that ceasing normal operation of a pipeline does not remove the pipeline from PHMSA 's jurisdiction. If you have abandoned a Part 195 jurisdictional pipeline according to 195.402(c)(10), the requirements no longer apply. The abandoned pipeline may not be returned to service unless the pipeline was maintained according to Part 195 requirements while it was abandoned, or meets the requirements of a newly designed and constructed pipeline. **Interpretation: PI-95-028 Date: 07-24-1995** Local officials have a clear role in emergency response that is encouraged by the pipeline safety standards. The pipeline safety standards require that pipeline operators establish and maintain liaison with local emergency response personnel. 49 C.F.R. § 195.402(c)(12). In addition, pipeline operators must have procedures for notifying local officials of pipeline emergencies and for coordinating with them preplanned and actual responses to those emergencies. 49 C.F.R. § 195.402(e)(7). Local officials may also participate in local response planning required of pipeline operators by regulations adopted under the Oil Pollution Act of 1990. **Interpretation: PI-94-032 Date: 10-17-1994** Based on the regulatory history, it's apparent that operators only have to identify their high risk facilities to comply with §195.402(c)(4). So, by identifying all its facilities, an operator would not only meet but exceed the requirements of §195.402(c)(4). In addition, §195.402(c)(4) does not require operators to have plans and priorities to respond to failures or malfunctions at facilities under that section. However, response plans are a [sic] essential part of the emergency procedures required by §195.402(e) and of the abnormal operation procedures required by § 195.402(d). Also, under §195.402(c)(6), operators must take steps to minimize the potential for hazards to occur at the facilities identified under §195.402(c)(4).

	Interpretation: PI-79-027 Date: 08-03-1979 The following responds to whether certain oil pipelines constructed prior to 1954 must meet the construction requirements of 49 CFR 195.210 and 195.248. In accordance with Section 195.200, the provisions of the Federal liquid pipeline safety standards to which you refer are construction standards which apply to "new" pipelines and "existing" pipelines that are relocated, replaced, or otherwise changed. As used in this section, the term "new" means a pipeline upon which construction was begun after March 31, 1970, and "existing" refers to a pipeline in operation or under construction on that date (see Section 195.402(d)). As construction standards, the "cover" requirements of Sections 195.210 and 195.248 are intended to apply at the time a new pipeline is constructed or an existing pipeline is replaced, relocated, or otherwise changed. The Federal standards do not require that construction burial depths be maintained over the operating life of pipelines. However, it should be noted that the requirements of Section 195.402(c) call for corrective action by the carrier whenever it discovers any condition that could adversely affect the safe operation of its pipelines. Such a condition could involve insufficient cover over a pipeline to protect it against external loads. **Interpretation: PI-78-0102- Date: 04-25-1978** While Part 195 includes a standard which sets minimum burial depths for pipelines at the time of construction, that standard does not require that those precise depths be maintained for the life of the pipeline. However, under another provision of Part 195 governing the operation and maintenance of pipelines (§195.402(c)), a pipeline carrier who discovers any condition that could adversely affect the safe operation of the pipeline must correct it within a reasonable time, and if the condition presents an immediate hazard, the carrier may not operate the pipeline until the condition is corrected. **Interpretation: PI-76-0118 Date: 10-04-1976** This agency prescribes and enforces safety regulations applicable to the design, construction, operation, and maintenance of petroleum pipelines in interstate or foreign commerce. These regulations, which are contained in 49 CFR Part 195, do not govern right-of-way disputes. Carriers are required, however, to provide security for their facilities (§195.436) and to take appropriate remedial action, including shutting down the affected part of a system, in the event of an adverse or hazardous situation §195.402(c)). The threat of outside interference would not relieve a carrier's responsibility for compliance with these and other applicable requirements in Part 195.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB 04-01, Hazards associated with pipeline de-watering systems.**

	On June 21, 2004, the Research and Special Programs Administration's Office of Pipeline Safety (RSPA/OPS) issued Advisory Bulletin ADB-04-01 to owners and operators of gas and hazardous liquid pipelines to consider the hazards associated with pipeline de-watering operations. This advisory bulletin was originally issued jointly with the Department of Labor's Occupational Safety and Health Administration (OSHA) as Safety and Health Information Bulletin SHIB 06-21-2004. Operators are strongly encouraged to follow the recommended work practices and guidelines to reduce the potential for unexpected separation of temporary de-watering pipes. RSPA/OPS recognizes the existence of hazards associated with testing pipelines and requires operators to protect their employees and the public during hydrostatic testing. Section 192.515(a) states that `` * * * each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing." In addition, Sec. 195.402(c) requires each pipeline operator to prepare and follow procedures for safety during maintenance and normal operation. **Advisory Bulletin ADB 02-03, Pipeline Safety: Gas and Hazardous Liquid Pipeline Mapping.** The Research and Special Programs Administration's (RSPA) Office of Pipeline Safety (OPS) is issuing this advisory to gas distribution, gas transmission, and hazardous liquid pipeline systems. Owners and operators should review their information and mapping systems to ensure that the operator has clear, accurate, and useable information on the location and characteristics of all pipes, valves, regulators, and other pipeline elements for use in emergency response, pipe location and marking, and pre-construction planning. This includes ensuring that construction records, maps, and operating history are readily available to appropriate operating, maintenance, and emergency response personnel. All gas and hazardous liquid pipeline operators must maintain an operating and maintenance plan that includes procedures for making construction records, maps, and operating history available to appropriate operating personnel to enable them to safely and effectively perform their duties (49 CFR 192.605 and 195.402). Furthermore, the hazardous liquid pipeline regulations at 49 CFR 195.404 explicitly require that the maps and records must include, at a minimum, the following information: (1) Location and identification of pipeline facilities. (2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines. (3) The maximum operating pressure of each pipeline. (4) The diameter, grade, type, and nominal wall thickness of all pipe. Not all this information need be on maps, but must be readily available to appropriate personnel.
Other Reference Material & Source	
Guidance Information	1. Records, maps, etc. must be available to personnel performing O&M functions. This may be electronic, current printed alignment sheets, etc.

	2. There also needs to be detailed process on how records or maps, etc. are updated so that the most current version is available in a timely manner to persons performing O&M functions. 3. The operator needs to define what information is necessary to determine that accident meets thresholds for reporting including who is to make the determination or the call to NRC. The call to NRC should occur within 2 hours. When information changes significantly (esp. death, injury, or estimated amount spilled), the operator is to re-call the NRC to update. (ADB-02-04) 4. The operator's procedure should state that an accident report is due in 30 days and that changes in information require a supplemental report be filed. Procedure should state who is responsible for submitting the report, etc. 5. The operator should have a communication plan for letting operating personnel know the causes of accidents and prevention measures to minimize potential recurrence. 6. The operator should have facility specific startup and shutdown procedures. 7. The operator should have procedures or practices in place for the use of explosion proof motors and outlets. Areas should be identified on location maps that denote NFPA Class 1, Div. 1 locations where vapors are anticipated. Hot work procedures should require tests for hazardous vapors in those designated areas. 8. The operator's procedures need to discuss monitoring, evacuation of vapors, LEL for "safe work", Hot Work permits, etc. 9. The operator's O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual. 10. Procedures are required for functions and facilities in a system. 11. Procedures are not just for the field personnel. 12. Procedures are required for tasks normally performed at the engineering, the operations control center, and other headquarters-type functions as applicable to O&M tasks. 13. The procedures should be clear, straight forward, and applicable to the company's system. 14. Abnormal operations procedures must be included for liquid pipeline operations. 15. Personnel conducting pipeline operations need direct access (either on paper or electronically) to procedures, without delay when emergencies arise. 16. It is acceptable for operators to use the manufacturer's recommended practices (engine books or other related literature) regarding the maintenance of the specific equipment at each location (these documents must be available at each location). It is also acceptable to post the specific start-up and shut-down instructions for each pump unit at or near the local control panel used for starting the equipment and having generic procedures in their O&M Plan. 17. Fail Safe generally means that equipment will automatically respond without exceeding the parameters set by the operator. This means not exceeding the MOP plus the 10% prescribed allowance (ref. §195.406) 18. It is an acceptable practice to identify their entire pipeline as an immediate response area if so designated in the operator's O&M Plan. 19. An abandoned pipeline must be physically isolated from active pipelines, disconnected from all sources of liquids, purged of liquids, and sealed at both ends. 20. Only abandoned (permanently removed from service) pipelines are exempt from Part 195 regulations with exception of abandonment inventory reporting requirements.

21. Inactive pipeline, which may or may not contain liquids, must meet all applicable requirements of Part 195. Operators sometimes do not completely abandon a pipeline and may sometimes use terms such as “idle”, “inactive”, or “out of service” to describe this situation. The regulations do not define “idle” or “inactive” pipe. Pipe is either considered active or abandoned. If a pipeline has not been abandoned according to the regulations, then it is active and the operator must ensure that the pipeline complies with all requirements of Part 195.
22. The OPS procedures required to protect employees from vapors in excavations is different and less stringent than the OSHA confined space procedures.
23. With regard to the potential overlap with OSHA rules. Section 4(b)(1) of the OSHA Act prohibits OSHA from exercising authority over working conditions when another agency exercises authority through regulation.
24. Areas where accidental ignition may occur include but are not limited to:
    a. Operating internal combustion engines
    b. Activities that could generate static electricity or electrical arcing
    c. Welding, cutting, and other hot work
    d. Using certain non-approved electric equipment (flashlights, power tools/equipment, etc.)
    e. Working on motors or appurtenances
    f. Working inside pipeline buildings
    g. Use of spark-producing hand tools; etc.
    h. Engine exhaust stack temperatures
25. Operators should maintain restricted access to hazardous areas, including safety zones for vehicular and air space domains.
26. §195.402(c)(13) is directed to procedures refinement, not employee evaluation.
27. The operator must show that some analysis has been performed to determine the adequacy of a procedure and, if found to be inadequate, made appropriate modifications. The analysis may include accident data, near-miss data, submissions of improvement to procedures from employees, meetings to discuss the procedures, job safety analysis, etc., and should include documentation showing the analysis, discussions, etc., that determined the procedure was adequate or inadequate.
28. It is acceptable to use third parties to conduct meetings with appropriate public officials on the behalf of the operator/s; however, the operator is ultimately responsible for compliance with this requirement.
29. Documentation must be available concerning a good faith attempt to include who was invited and who attended to meet the requirements of code and topics discussed.
30. Appropriate materials must be sent to the public officials that were invited but did not attend.
31. Reviewing performance of an operation or maintenance task for purposes of training and qualification by itself is not adequate for satisfying the requirements of § 195.402(c)(13). Procedures for, and evidence that work reviews conducted for personnel training and qualification purposes were performed for the purpose of determining the effectiveness of procedures are also needed.
32. An operator’s written procedures on addressing local emergencies should address its response to natural disasters that pose a threat to the pipeline.
33. Final Order Guidance:
    a. Tampa Pipeline Corporation [2-2008-6002] (Apr. 26, 2010): Section 195.402(c)(12) requires “pipeline operators to establish programs that are specifically designed to maintain liaison with response officials in all cities

	and counties where a pipeline is located. The[se] liaison [activities] must cover all possible emergency scenarios to ensure proper coordination with those officials who would respond to potential emergencies. Operators are expected to maintain liaison through regular meetings held at least once a year. . . . Operators are also expected to document their liaison activities by producing appropriate records, such as copies of invitations sent by the company to response officials, lists of officials who attended liaison meetings, agendas showing topics addressed during the meetings, and materials provided to officials at the meeting or sent to those officials who did not attend." CO/CP b. Enbridge Energy Partners, LP [3-2008-5011](Aug. 17, 2010): Training and qualification reviews performed for purposes of evaluating an individual's knowledge and ability to perform a covered task under Subpart G—Qualification of Pipeline Personnel do not establish compliance with §195.402(c)(13) by itself. The regulation "requires each operator to have and follow written procedures for periodically reviewing the work done by operator personnel to determine the effectiveness of the operating and maintenance procedures and for taking corrective action where deficiencies are found to ensure safety during operations and maintenance [activities]." Reviewing work for purposes of training and qualification was not an adequate substitute for complying with §195.402(c)(13). CO/CP c. ExxonMobil Pipeline Company [520135007] (January 23, 2015): The written procedures for handling emergencies must include, among other things, provisions for promptly and effectively responding to emergencies, including fire or explosion, accidental release, hazardous conditions, and natural disasters affecting the pipeline facility.
Examples of a Probable Violation or Inadequate Procedures	1. There is no written procedure or the operator did not follow the procedure. 2. The procedure is too general to establish specific requirements for the task being performed. 3. The procedure simply repeats the regulation. 4. The procedure for taking adequate precautions in excavated trenches is less stringent than OSHA's confined space procedures. 5. The operator's procedures for taking adequate precautions in excavated trenches do not include the use of appropriate instruments to test the atmosphere in the trench. 6. Reviewing work done for purposes of training and qualification, as the sole method of review, is not adequate to meet the requirements of §195.402(c)(13). 7. The written procedures for responding to emergencies do not provide guidance for the operator's response to fire, explosion, accidental release, hazardous condition, or natural disasters that could threaten the pipeline. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Copy of operator's procedures or applicable portion that shows omission or deficiency.

	2. Documented conversations with the operator.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.402(d)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies
Existing Code Language	(d) Abnormal operation. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded; (1) Responding to, investigating, and correcting the cause of; (i) Unintended closure of valves or shutdowns; (ii) Increase or decrease in pressure or flow rate outside normal operating limits; (iii) Loss of communications; (iv) Operation of any safety device; (v) Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property. (2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation. (3) Correcting variations from normal operation of pressure and flow equipment and controls. (4) Notifying responsible operator personnel when notice of an abnormal operation is received. (5) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-22, 46 FR 38357, 07-27-1981
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	

1. Checking for variations from normal operation after abnormal operation may be a review of pressure records or it may entail a hydraulic analysis along the pipelines alignment to account for elevation variations.
2. Abnormal operations do not pose an immediate threat to life or property as do emergency conditions.
3. Abnormal operations are generally less severe, but could escalate to emergency conditions if not promptly corrected.
4. Any pipeline operator that chooses to treat abnormal operations as emergency conditions still must comply with §195.402(d) and have separate procedures for abnormal operations.
5. The operator's O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual.
6. Procedures are required for all facilities in the system.
7. The procedures are not just for the field personnel.
8. Procedures are also required for tasks normally performed at the operations control center, engineering and other headquarters-type functions as applicable to O&M tasks.
9. The procedures should be clear, straight forward, and applicable to the company's system.
10. All these procedures must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year.
11. §195.402(d)(5) is directed to procedures refinement, not employee evaluation.
12. Operators may apply various techniques to determine the effectiveness of its abnormal O&M procedures, some examples are:
    a. Root cause analysis
    b. Post event reports
    c. Tailgate meeting agenda item
    d. Near-miss and accident investigation analysis
    e. Simulation or event re-construction reviews
    f. Abnormal operations drills and mock exercises
    g. Employee suggestions
13. Refinement and efficiency of procedures must not compromise safety.
14. Abnormal operations should be trended and reviewed. Consistently occurring abnormal operations are an indication that pipeline operations need to be modified to prevent possible failure.
15. Abnormal operations should be documented – typically by a form or work management system, etc. to facilitate review and trending by operations personnel to make corrections to prevent system from exceeding design limits.
16. Abnormal operations for particular lines or systems need to be defined.
17. For loss of communications the operator should define how long this is allowed before personnel are sent to the facility to monitor pipeline. There should be direction in use of back-up communications, or the local facility's PLC programming can "drive" the station to lower set points when PLC loses communication with SCADA.
18. MOP does not have to be exceeded for an event to be considered an abnormal operation.

19. Final Order Guidance:
    a. ***Potomac Electric Power Company and Support Terminal Services* [1-2000-6003] (Jun. 2, 2004)**: For purposes of 49 C.F.R. § 195.402(d), an abnormal operation is not limited solely to instances where the internal design or maximum operating pressure (MOP) of a hazardous liquid pipeline is

	exceeded. Any increase or decrease in pressure or flow rate outside of normal operating limits, as well as any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property, is an abnormal operation under § 195.402(d). CO/CP
Examples of a Probable Violation or Inadequate Procedures	1. There is no written procedure or the operator did not follow the procedure. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Copy of O&M plan or applicable procedure that shows omission or deficiency in the plan. 2. The only procedure for addressing vapors in excavated trenches is OSHA's confined space procedures. 3. Copy of O&M plan or applicable portion that shows omission or deficiency in the plan. 4. Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.402(e)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies
Existing Code Language	(e) Emergencies. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs; (1) Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action. (2) Prompt and effective response to a notice of each type emergency, including fire or explosion occurring near or directly involving a pipeline facility, accidental release of hazardous liquid or carbon dioxide from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities. (3) Having personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency. (4) Taking necessary action, such as emergency shutdown or pressure reduction, to minimize the volume of hazardous liquid or carbon dioxide that is released from any section of a pipeline in the event of a failure. (5) Control of released hazardous liquid or carbon dioxide at an accident scene to minimize the hazards, including possible intentional ignition in the cases of flammable highly volatile liquid. (6) Minimization of public exposure to injury and probability of accidental ignition by assisting with evacuation of residents and assisting with halting traffic on roads and railroads in the affected area, or taking other appropriate action. (7) Notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid. (8) In the case of failure of a pipeline transporting a highly volatile liquid, use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas. (9) Providing for a post accident review of employee activities to determine whether the procedures were effective in each emergency and taking corrective action where deficiencies are found. (10) Actions required to be taken by a controller during an emergency in accordance with §195.446.
Origin of Code	Original Code 195-15, 44 FR 41197, 07-16-1979
Last Amendment	Amdt. 195-93, 74 FR 63310, 12-03-2009
Interpretation Summaries	**Interpretation: PI-95-028 Date: 07-24-1995** Local officials have a clear role in emergency response that is encouraged by the pipeline safety standards. The pipeline safety standards require that pipeline operators establish and maintain liaison with local emergency response personnel. 49 C.F.R. § 195.402(c)(12). In addition, pipeline operators must have procedures

	for notifying local officials of pipeline emergencies and for coordinating with them preplanned and actual responses to those emergencies. 49 C.F.R. § 195.402(e)(7). Local officials may also participate in local response planning required of pipeline operators by regulations adopted under the Oil Pollution Act of 1990. **Interpretation: PI- 83-104 Date: 04-13-1983** There has never been a specific requirement in Part 195 that operators notify land owner in the event of an accident. However, since July 1980, §195.440 requires that operators have a continuing public educational program to facilitate prompt response to pipeline emergencies and under §195.402(e) (7) operators must notify public officials of emergencies on their systems. These rules and related requirements expanded more general rules relating to operating procedures in normal, abnormal, and emergency situations that were in effect in 1978 under §195.402(a) (See Amendment 195-15; 44 FR 41197, July 16, 1979). You should review the operator's procedures established in conformance with §195.402(a) in 1978 for specifics about the steps to be taken in response to an accident.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-10-08, Emergency Preparedness Communications** To further enhance the Department's safety efforts, PHMSA is issuing this Advisory Bulletin about emergency preparedness communications between pipeline operators and emergency responders. To ensure a prompt, effective, and coordinated response to any type of emergency involving a pipeline facility, pipeline operators are required to maintain an informed relationship with emergency responders in their jurisdiction. PHMSA reminds pipeline operators of these requirements, and in particular, the need to share the operator's emergency response plans with emergency responders. PHMSA recommends that operators provide such information to responders through the operator's liaison and public awareness activities, including during joint emergency response drills. PHMSA intends to evaluate the extent to which operators have provided local emergency responders with their emergency plans when PHMSA performs future inspections for compliance with relevant requirements. **Advisory Bulletin ADB 05-03, Pipeline Safety: Planning for Coordination of Emergency Response to Pipeline Emergencies.** This document alerts pipeline operators about the need to preplan for emergency response with utilities whose proximity to the pipeline may impact the response. Coordination with electric and other utilities may be critical in responding to a pipeline emergency. Preplanning would facilitate actions that may be needed for safety, such as removing sources of ignition or reducing the amount of combustible material. Existing regulations for both gas and hazardous liquid pipelines require operators to have emergency procedures to address pipeline emergencies. The key element of

	these requirements, which are located at 49 CFR 192.615 and 195.402(e), is to plan response before the emergency occurs. Because pipelines are often located in public space rather than in controlled access areas, planning emergency response must include more than internal plans. The regulations explicitly require that operators include procedures for planning with fire, police and other public officials to ensure a coordinated response. It is also important to plan a coordinated response with owners of other utilities in the vicinity of the pipeline. The operations of these utilities may provide sources of ignition for the product released from a pipeline, may increase the burning time of fires that have already started, or may delay responders who are attempting to make the situation safe rapidly. **Advisory Bulletin, ADB-94-04, Coordinating Emergency Planning with Offshore Producers.** This bulletin calls the attention of offshore operators to an NTSB safety recommendation regarding the need for emergency planning and coordination between themselves and offshore producers. **Advisory Bulletin ADB-93-03, Advisory to Owners and Operators of Hazardous Liquid and Natural Gas Facilities in Area of Flooding** Extended periods of rain and flooding in Midwestern states have resulted in the potential for conditions that threaten the safety of pipelines. The Office of Pipeline Safety (OPS), RSPA, has issued this advisory bulletin to pipeline operators in those flood areas to advise them of measures they should consider assuring the safety of those pipelines. In particular, pipeline operators should review emergency plans to assure they adequately cover conditions possible in the current severe flooding. For compliance with 49 CFR Sections 192.615(a)(3)(iv) Emergency Plans and 195.402(e)(2) Emergencies, pipeline operators must develop procedures for a prompt and effective response to natural disasters including flooding.
Other Reference Material & Source	

Guidance Information	1. Generic emergency plans are fine for the whole company; however, they must be specific for the individual locations covered by the local emergency plan. 2. Operators must have a contact list of local fire and other public emergency agencies and be readily available to the appropriate personnel. 3. Emergency procedures must contain enough specificity to give the employees enough information on who to call, what to do, where and what the equipment is, etc. 4. References must be included in the emergency plan, if material in other manuals are to be used at the site i.e. Safety Manuals, OPA Oil Spill Response Plan, etc. 5. Individuals who normally receive calls for the operator should be appropriately trained to identify the situation, direct callers to seek safety first, and then gather critical information to promptly initiate the operator's response efforts. 6. Violation of §195.402(e)(9) has been cited for inadequate post accident review when recommendations were made but were not implemented by the operator. 7. Procedures need to describe specifically how reports from public officials or emergency responders following an emergency are to be classified and what actions are to be taken. 8. Emergency procedures shall address NRC notification and other notification requirements.
Examples of a Probable Violation or Inadequate Procedures	1. There is no written procedure or the operator did not follow the procedure. 2. Outdated or incomplete listing of contact information for local fire and emergency agencies. 3. No listing of where emergency resources are located. 4. No listing of how to access emergency isolation valves. 5. The operator does not have a procedure for responding to an emergency that may impact their pipeline. 6. The operator has no listing for the railroad road-master or individual with the authority to shut-down a segment of railroad that parallels a pipeline in their assigned area. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Copy of emergency procedures or applicable portion that shows omission or deficiency in the plan. 2. Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.402(f)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies
Existing Code Language	(f) Safety-related condition reports. The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §195.55.
Origin of Code	Original Code Document, 53 FR 24942, 07-01-1988
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	§195.55 Reporting safety-related conditions. (a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §195.56 the existence of any of the following safety-related conditions involving facilities in service: (1) General corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result. (2) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood that impairs its serviceability. (3) Any material defect or physical damage that impairs the serviceability of a pipeline. (4) Any malfunction or operating error that causes the pressure of a pipeline to rise above 110% of its maximum operating pressure. (5) A leak in a pipeline that constitutes an emergency. (6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline. (b) A report is not required for any safety-related condition that- (1) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or that occurs offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water:

	(2) Is an accident that is required to be reported under §195.50 or results in such an accident before the deadline for filing the safety-related condition report: or (3) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline. §195.56 Filing safety-related condition reports. (a) Each report of a safety-related condition under §195.55(a) must be filed (received by the Associate Administrator, OPS) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by telefacsimile (fax), dial (202) 366-7128. (b) The report must be headed "Safety-Related Condition Report" and provide the following information: (1) Name and principal address of operator. (2) Date of report. (3) Name, job title, and business telephone number of person submitting the report. (4) Name, job title, and business telephone number of person who determined that the condition exists. (5) Date condition was discovered and date condition was first determined to exist. (6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline. (7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored. (8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up future corrective action, including the anticipated schedule for starting and concluding such action.
Guidance Information	1. The operator must have a procedure. 2. The operator must meet the requirements of §195.452 for safety related conditions that occur in pipeline segments that could impact a High Consequence Area. 3. The operator's SRCR process does not meet the requirements of §195.56. 4. Field operations and maintenance personnel, controllers or corrosion personnel are expected to recognize potential safety-related conditions. 5. Operators should designate what personnel are ultimately responsible to assess and determine the existence of safety-related conditions. 6. Anomalies that are found during IMP ILI tool runs may fall under the reporting requirements for an SRCR.
Examples of a Probable	1. There is no written procedure or the operator did not follow the procedure.

Violation or Inadequate Procedures	*Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Copy of O&M plan or applicable procedure that shows omission or deficiency in the plan. 2. Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.403
Section Title	Emergency Response Training
Existing Code Language	(a) Each operator shall establish and conduct a continuing training program to instruct emergency response personnel to: (1) Carry out the emergency procedures established under §195.402 that relate to their assignments; (2) Know the characteristics and hazards of the hazardous liquids or carbon dioxide transported, including, in the case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions; (3) Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquid or carbon dioxide spills, and to take appropriate corrective action; (4) Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage; and (5) Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. (b) At intervals not exceeding 15 months, but at least once each calendar year, the operator shall: (1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section; and (2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective. (c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under §195.402 for which they are responsible to ensure compliance.
Origin of Code	Amdt. 195-15, 44 FR 41197, 07-16,-1979
Last Amendment	Amdt. 195-78, 68 FR 53526, 09-11-2003
Interpretation Summaries	**Interpretation: PI-09-0003 Date: 06-24-2009** Under PHMSA's performance based regulations, pipeline operators can use a variety of methods and resources to provide emergency response training if they meet all the training requirements and keep adequate records to show compliance. Therefore, PHMSA will accept non-U.S. emergency response training for purposes of assessing compliance with Parts 194 and 195 for non-U.S. based emergency response personnel in the same way we would accept and review a U.S. based training program during a compliance audit. The program must provide all the required training and must adequately document the training in records available for inspection in the U.S. by PHMSA during inspections.

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. It is permissible to have on-line access to an electronic copy (via Network or CD) of the Emergency Plan; however, appropriate portions of the plan must be readily accessible locally, even if network connectivity to headquarters is temporarily not available. The same is true for maps showing the location of emergency valves and other pertinent information. The operator should have backup material available in the event of a loss of Network access. 2. Individuals who normally receive calls for the operator should be appropriately trained to identify the situation, direct callers to seek safety first, and then gather critical information to promptly initiate the operator's response efforts. 3. Emergency training programs shall include initial employee training, with annual (not to exceed 15 months) individual refresher training. 4. Emergency training should cover different levels of responsibility and complexity, including, as applicable to the operator, personnel from the control center, managers and/or supervisors, field personnel, patrol pilots, communications systems, SCADA, etc. 5. Emergency exercises may include tabletop scenarios, on-scene, mock, and/or corporate-wide exercises, simulated control room exercises, etc. Many of these exercises are required by OPA and can be utilized to meet this requirement. 6. One method operators use to review performance, make appropriate changes, and verify that supervisors maintain a thorough knowledge, is by critiquing the performance of emergency exercises. All simulated and real emergencies should be self-critiqued, with deficiencies identified and recommendations made and followed up on. 7. Contractor personnel shall be trained on the operator's emergency response plan when performing an activity where an emergency might occur.
Examples of a Probable Violation or Inadequate Procedures	1. The lack of a procedure is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did not follow the written procedure. 4. A written, continuing training program has not been established. 5. Training program procedures are/have not been followed. 6. No (or insufficient) documentation that personnel have been trained per the requirements of §195.403(a). 7. No documentation that the review with personnel is being performed at the prescribed frequency. 8. Appropriate changes to the training program are not made. 9. No requirement or documentation that supervisors maintain a thorough knowledge of the prescribed procedures. 10. Contractor's not trained on the emergency plan when performing an activity where an emergency might occur. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable*

	Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. Written training program and procedures. 2. Training records, certifications, education history. 3. Documented statements of the operator. 4. Prescribed O&M and emergency response records required of §195.402. 5. Accident investigation reports. 6. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.404
Section Title	Maps and Records
Existing Code Language	(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information; (1) Location and identification of the following pipeline facilities; (i) Breakout tanks; (ii) Pump stations; (iii) Scraper and sphere facilities; (iv) Pipeline valves; (v) Facilities to which §195.402(c)(9) applies; (vi) Rights-of-way; and (vii) Safety devices to which §195.428 applies. (2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines. (3) The maximum operating pressure of each pipeline. (4) The diameter, grade, type and nominal wall thickness of all pipe. (b) Each operator shall maintain for at least 3 years daily operating records that indicate- (1) The discharge pressure at each pump station; and (2) Any emergency or abnormal operation to which the procedures under §195.402 apply. (c) Each operator shall maintain the following records for the periods specified; (1) The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe. (2) The date, location, and description of each repair made to parts of the pipeline other than pipe shall be maintained for at least 1 year. (3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-73, 66 FR 66993, 12-27-2001
Interpretation Summaries	**Interpretation: PI-97-0102 Date: 10-01-1997** OPS considers an appropriate minimum time interval for electronically recorded pressure data as that time interval which is frequent enough to collect the pressures attained during normal and abnormal conditions, such that the recorded data could be assembled to create a facsimile of the pressures that actually occurred, including the magnitude and time interval of all elevated pressures. This approach requires the operator to review the dynamics of their individual pipeline to determine what interval would be necessary and to ensure that all elevated pressures are captured. An inspector could then review the operating

	dynamics of the pipeline to determine if the chosen interval is small enough and that the recorded data reasonably agrees with actual field data. **Interpretation: PI-92-015 Date: 04-06-1992** Section 195.404(c)(3) does not prohibit operators from maintaining the required records on magnetic media. Also, original hard-copy (paper) records need not be retained after their conversion to magnetic media. However, like the original hard copy records, magnetic media records must contain detailed information to comply with the recordkeeping requirements of §195.404(c)(3).
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-08-07, National Pipeline Mapping System.** NPMS submissions would represent physical assets as of December 31 of the previous year. PHMSA also suggests that Operator ID numbers (internal DOT numbers assigned by PHMSA to the operator for specific assets) in annual report submissions match the same assets described in NPMS submissions. Operators who choose to follow this guidance will use the same Operator ID number to describe a pipeline or LNG asset in both the annual report and NPMS submission beginning with their 2009 submissions. This does not apply to pipeline operators who have requested and been assigned only one Operator ID number. Synchronizing the Operator ID numbers will alleviate confusion in identifying operator assets and improve PHMSA's ability to accurately describe the pipeline operated by a specific pipeline operator. The ability to accurately identify and track operator physical assets is beneficial to PHMSA, pipeline operators, and all stakeholders who utilize our data, and ultimately helps promote pipeline safety. **Advisory Bulletin ADB-03-09, Potential Service Disruptions in Supervisory Control and Data Acquisition Systems** Each pipeline owner or operator should review their procedures for the upgrading, configuring, maintaining, and enhancing its SCADA system. If not well thought out and thoroughly tested, such changes could cause inadvertent service disruptions in the SCADA system. Resulting conditions could impede controllers responsible for operating the pipeline from promptly recognizing and reacting to abnormal conditions, and could potentially impact the controllers' abilities to restore normal operations. Owners and operators should ensure that SCADA system modifications do not degrade overall SCADA performance to an unacceptable level. To further reduce the potential effect of service disruptions, responsible personnel should coordinate significant and non-routine SCADA modifications to occur at times when no significant changes to pipeline operations are anticipated. **Advisory Bulletin ADB-02-03, Accurate information on location of pipelines.** Owners and operators should review their information and mapping systems to ensure that the operator has clear, accurate, and useable information on the location and characteristics of all pipes, valves, regulators, and other pipeline elements for

	use in emergency response, pipe location and marking, and pre-construction planning. This includes ensuring that construction records, maps, and operating history are readily available to appropriate operating, maintenance, and emergency response personnel. All gas and hazardous liquid pipeline operators must maintain an operating and maintenance plan that includes procedures for making construction records, maps, and operating history available to appropriate operating personnel to enable them to safely and effectively perform their duties (49 CFR 192.605 and 195.402).
Other Reference Material & Source	
Guidance Information	1. The operator must have written procedures. 2. Updated maps, schematics, documents, drawings, and display screens that reflect current conditions and are critical to operations, the control center, and emergency response situations must be available to operating personnel. 3. Operators should have a change control process to maintain documents current. 4. Documents, drawings and display screens should be readily available to appropriate personnel. 5. Records requirements include the operator's pretested and stock pipe inventory. 6. Detailed pump discharge pressure records must be retained for 3 years. 7. When SCADA is used as the discharge pressure record utility, field data collection intervals (polling) of 20 seconds or faster is considered adequate enough for compliance to track pump discharge pressures (some hydraulic impulse phenomena may not be recorded at this interval). Associated data archiving must not diminish the accuracy or resolution of the data. 8. Records may be in the form of computer records or on magnetic tape but must be reproducible or available in a reviewable format.
Examples of a Probable Violation or Inadequate Procedures	1. Lack of procedures is a violation of Section 195.402. 2. Operator does not have complete and current maps or records. 3. Operator's records do not contain at least 3 years of detailed operating pressure records. 4. Operator's records do not contain maintenance, test and repair records for the prescribed time periods. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. O&M procedures. 2. Operations and maintenance records. 3. Documented comments from the operator.

	4. Copies of maps and records. If the records are missing, get an example of the record to be kept, or the record of the inspection prior and/or post to the inspection that was missed. 5. Photographs. 6. Lack of procedures.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.405
Section Title	Protection Against Ignitions and Safe Access/Egress Involving Floating Roofs
Existing Code Language	(a) After October 2, 2000, protection provided against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with API RP 2003 (incorporated by reference, see § 195.3), unless the operator notes in the procedural manual (§195.402(c)) why compliance with all or certain provisions of API RP 2003 is not necessary for the safety of a particular breakout tank. (b) The hazards associated with access/egress onto floating roofs of in service aboveground breakout tanks to perform inspection, service, maintenance, or repair activities (other than specified general considerations, specified routine tasks or entering tanks removed from service for cleaning) are addressed in API Pub 2026 (incorporated by reference, see § 195.3). After October 2, 2000, the operator must review and consider the potentially hazardous conditions, safety practices, and procedures in API Pub 2026 for inclusion in the procedure manual (§195.402(c)).
Origin of Code	Original Code Document, 64 FR 15926, 04-02-1999
Last Amendment	Amdt. 195-99, 80 FR 187, 01-05-2015.
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	API Recommended Practice 2003, ''Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents'' (7th edition, January 2008). (API RP 2003), IBR approved for § 195.405(a). API Publication 2026, ''Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service'' (2nd edition, April 1998, reaffirmed June 2006). (API Pub 2026), IBR approved for § 195.405(b).
Guidance Information	1. The operator must have written procedures.
Examples of a Probable Violation or Inadequate Procedures	1. Lack of a procedure is a violation of 195.402. 2. Lack of records is a violation of 195.404. 3. Procedures do not convey a valid justification as to why compliance with all or certain provisions of API Recommended Practice 2003 are not necessary. 4. Inadequate documentation that protection against ignition is provided. 5. Inadequate documentation that the operator has reviewed and considered the potentially hazardous conditions, safety practices and procedures in API

	Publication 2026 "Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service" for inclusion in the procedure manual. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Written procedures (or lack of). 2. Engineering drawings/schematics. 3. Observations. 4. Photographs. 5. Accident investigation. 6. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.406
Section Title	Maximum Operating Pressure
Existing Code Language	(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following: (1) The internal design pressure of the pipe determined in accordance with §195.106. However, for steel pipe in pipelines being converted under §195.5, if one or more factors of the design formula (§195.106) are unknown, one of the following pressures is to be used as design pressure: (i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME/ANSI B31.8 (incorporated by reference, see § 195.3), reduced by the appropriate factors in §§195.106(a) and (e); or (ii) If the pipe is 323.8 mm (12 : in) or less outside diameter and is not tested to yield under this paragraph, 1379 kPa (200 psig). (2) The design pressure of any other component of the pipeline. (3) Eighty percent of the test pressure for any part of the pipeline which has been pressure tested under Subpart E of this part. (4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under §195.305. (5) For pipelines under §§195.302(b)(1) and (b)(2)(i), that have not been pressure tested under Subpart E of this part, 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted. (b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.
Origin of Code	Original Code Document, 35 FR 17183, 11-07-70
Last Amendment	Amdt. 195-99, 80 FR 184, 01-05-2015.
Interpretation Summaries	**Interpretation: PI-91-008 Date: 03-25-1991** The operator of a regulated pipeline may not own the device on a refiner's grounds that is necessary to control pressure is responsible for compliance with Part 195 standards governing that device, because the operator is using or relying on the device to operate its pipeline according to §195.406(b).

Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-11-01, Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures.
Other Reference Material & Source	
Guidance Information	1. The operator must have written procedures for establishing maximum operating pressure. 2. To determine if any of the requirements of Part 195 apply to a pipeline or a piping facility, refer to §195.1 and related interpretations and amendments. If pipelines are found to be "excepted" under §195.1(b), Part 195 regulations do not apply. 3. For criteria that apply to converted pipelines, refer to §195.5. 4. To determine the MOP, a pressure must be calculated under each of the applicable criteria in §195.406(a). MOP is the lowest of these pressures. 5. §195.406(b) expressly allows operators to exceed MOP by 10% in other than normal situations. For example, a temporary pressure boost in an attempt by the operator to dislodge a stuck pig in a pipeline would not violate §195.406(b), if the resultant pressure does not exceed 110% of MOP. 6. Surge pressures that occur for brief periods during start-up and shutdown which exceed the MOP, but not above 110% of MOP, may be considered as being normal operating conditions. Continuing operations above MOP is not allowed. 7. It is not a violation for operators to set discharge control pressure as high as MOP. 8. MOP of a pipeline segment must take into consideration both pump station discharge and pressure gradient profile along the entire segment. 9. The design pressure of components is not prescribed in specific terms as it is for pipe under §195.106. Although sound design principles may require that a manufacturer's pressure rating and applicable factors in consensus standards be considered in determining the design pressure of a component, a pipeline operator is free under Part 195 to use equally sound principles to derive an independent design pressure. 10. Administrative change control procedures are considered a part of the pressure control system. (§195.406(b)) 11. The operator must establish the MOP of a low-stress pipeline according to this section before transportation begins or before July 3, 2009, if the pipeline exists on July 3, 2008. (See §195.11(b)(5)).

	12. Failure to establish local set points of overpressure protection equipment in accordance with the established MOP, regardless of adjustments to a SCADA system's programmable logic controls, is inadequate. 13. An operator's SCADA system may not serve as a substitute for proper local protective equipment. 14. Final Order Guidance: ***a. Kinder Morgan Energy Partners, LP [4-2006-5023] (Aug. 31, 2010): Inherent in the requirement imposed under 49 C.F.R. § 195.406(b)—i.e., to provide adequate controls and protective equipment to ensure that the pressure in a pipeline during surges or other variations from normal operations does not exceed 110 percent of the established maximum operating pressure—is an obligation on the part of the operator to use reasonable means to determine what controls and protective equipment are adequate for a particular pipeline system and to document the basis for that determination. CO/CP*** ***b. Enterprise Products Operating, LLC [4-2007-5015] (Dec. 2, 2009): An operator must consider the potential for pressure surges in making a determination under 49 C.F.R. § 195.406(b) about the adequacy of the controls and protective equipment for a particular pipeline system. CO/CP*** ***c. Dixie Pipeline Company [2-2004-5009] (Oct. 21, 2004): The pressure of a pipeline may not exceed the maximum operating pressure (MOP) as established under 49 C.F.R. § 195.406(a) during normal operations. The pressure of a pipeline may not exceed 110 percent of MOP during surges or other variations from normal operations under 49 C.F.R. § 195.406(b). CP*** ***d. Magellan Midstream Partners, LP [CPF No. 4-2012-5010] (September 2, 2014): The exceptions to the maximum operating limit in § 195.406(a) are for "surge pressures and other variations from normal operations." Regardless of the cause of the variation, the excursion is not permitted to exceed MOP for an indefinite amount of time. Pressure excursions lasting more than ten minutes on multiple occasions over the course of several years, even if unintentional, are not merely "variations from normal operations" permitted under the regulation CP/CO.*** ***e. ONEOK NGL Pipeline, L.P. [3-2012-5012] (June 12, 2014): The operator did not provide adequate controls and protective equipment to control the pressure in a pipeline during surges or other variations from normal operations because it failed to establish local set points of overpressure protection equipment in accordance with the established MOP, regardless of adjustments to a SCADA system's programmable logic controls.*** ***f. ENMARK ENERGY INC [2-2014-6002] (May 2, 2014) The Notice alleged that Enmark did not control the valves and equipment needed to ensure that the Sandhill and Air Liquide lines did not exceed the 110 percent as set forth in 49 C.F.R. § 195.406(b). During the inspection, Enmark acknowledged that the pressure of the pipelines was controlled by the upstream operator. Enmark was unable to demonstrate that appropriate procedures, personnel qualifications, and recordkeeping had been undertaken by the upstream operator on behalf of Enmark that satisfied Enmark's responsibilities concerning the use of adequate controls and protective equipment necessary to control the pipeline pressures on its Sandhill and Air Liquide lines.***

Examples of a Probable Violation or Inadequate Procedures	1. Lack of procedures is a violation of 195.402. 2. Lack of records is a violation of 195.404. 3. Operator has/is operating a pipeline above the MOP that is prescribed under §195.406(a), except for surge pressures or other variations from normal operations. This may include failure of the operator to provide adequate test pressure or highest operating pressure records, if §195.406(a)(5) applies. 4. Operator did not have required equipment properly set to protect the MOP. This includes foreign lines that interconnect with their lines. 5. The pipeline pressure exceeded 110% of MOP under surge pressures or other variations from normal operations. 6. Operator's pressure control and protective equipment is not adequate to control the pipeline segment's pressure within 110% of MOP as prescribed in §195.406(b). 7. Set points of relief devices set incorrectly. 8. Operator has not established MOP in accordance with this section or does not have adequate documentation to demonstrate compliance with this section. 9. Pressure control equipment did not operate properly. 10. Repairs are not suitable for the established MOP. 11. Failure to adjust the local set points of overpressure protective equipment in accordance with the established pipeline MOP for surges or other variations from normal operations not to exceed 110 percent of the operating pressure limit. 12. The operator relies on upstream operators to provide controls and protective equipment to control the pressure in its pipelines, **<u>and</u>** fails to demonstrate that the upstream operator has appropriate procedures and recordkeeping. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Documentation of facility MOP determination. 2. Facility specifications, records, nameplates. 3. Engineering drawings and records. 4. Component design and test data. 5. Elevation profiles. 6. Test records or operating pressure logs that establish MOP. 7. Operating pressure records (electronic and/or paper, SCADA). 8. Operating schematics. 9. Pressure control/relief equipment maintenance procedures; equipment inspection and test records. 10. Operator's surge analyses, pipeline response model (under abnormal or transient conditions). 11. Documented comments from the operator. 12. Accident investigation report. 13. Abnormal or emergency operation reports. 14. Unscheduled equipment shutdown records. 15. Manufacturer's component installation recommended procedures. 16. Lack of procedures or records.

Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.408
Section Title	Communications
Existing Code Language	(a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system. (b) The communication system required by paragraph (a) of this section must, as a minimum, include means for: (1) Monitoring operational data as required by §195.402(c)(9); (2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action; (3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and, (4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-22, 46 FR 38357, 07-27-1981
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin, ADB-03-09, Potential Service Disruptions in SCADA Systems** RSPA's Office of Pipeline Safety (RSPA/OPS) is issuing this advisory notice to owners and operators of gas and hazardous liquid pipelines who use Supervisory Control and Data Acquisition (SCADA) systems. Pipeline owners and operators should establish thorough testing regimes when they design and implement modifications and enhancements of their SCADA systems. Owners and operators should consider using off-line or developmental workstations to test changes, then deploy the changes on-line under close monitoring at times when few operational changes are expected on the pipeline. Applying these techniques will help ensure that changes in the SCADA system environment do not have an unexpected effect on pipeline operations. **Advisory Bulletin, ADB-99-03, Potential Service Interruptions in Supervisory Control and Data Acquisition Systems.** Each pipeline operator should review the capacity of its SCADA system to ensure that the system has resources to accommodate normal and abnormal operations on its pipeline system. In addition, SCADA configuration and operating parameters should be periodically reviewed, and adjusted if necessary, to assure that the SCADA computers are functioning as intended. Further, operators should assure

	system modifications do not adversely affect overall performance of the SCADA system. We recommend that the operator consult with the original system designer.
Other Reference Material & Source	
Guidance Information	1. The operator must have written procedures. 2. Transmission of information refers to both voice and operational data. 3. Operators can adequately monitor operations by various means, one of which may be a SCADA system. 4. Procedures for actual use of communications system may be in other documents, e.g. emergency plans and procedures. 5. Operators are not required to have SCADA systems. 6. Emergency response vehicles shall have two-way vocal communication and operators shall have sufficient means of communication to handle emergency situations. 7. Adequate monitoring includes an ongoing awareness of the pipeline's condition, either by an individual monitoring a remote SCADA system or someone watching local gauges or listening for established alarms. 8. A 24-hour phone number must be provided; although recorded messages can be announced, there must be means to speak to the operator's personnel.
Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. Two-way communications are not available, did not function, or are inadequate during emergency and abnormal situations. 4. Unmanned facilities that are not being adequately monitored. 5. 24-hour phone number that does not provide contact with an individual qualified to receive emergency calls. 6. SCADA alarms that were ignored or not addressed preceding an emergency or abnormal operating condition. 7. Operators have not defined how they comply with this section. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Photos. 2. Job descriptions. 3. Contact information sheet for local fire and emergency agencies. 4. Dictated phone message monologue. 5. SCADA display printouts. 6. Station piping & instrument drawings. 7. Lack of documentation of how the operator complies with this section. 8. Lack of procedures or records.

Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.410
Section Title	Line Markers
Existing Code Language	(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following: (1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known. (2) The marker must state at least the following on a background of sharply contrasting color: (i) The word "Warning," "Caution," or "Danger" followed by the words "Petroleum (or the name of the hazardous liquid transported) Pipeline," or "Carbon Dioxide Pipeline," all of which, except for markers in heavily developed urban areas, must be in letters at least one inch (25mm) high with an approximate stroke of one-quarter inch (6.4mm). (ii) The name of the operator and a telephone number (including area code) where the operator can be reached at all times. (b) Line markers are not required for buried pipelines located- (1) Offshore or at crossings of or under waterways and other bodies of water; or (2) In heavily developed urban areas such as downtown business centers where- (i) The placement of markers is impracticable and would not serve the purpose for which markers are intended; and (ii) The local government maintains current substructure records. (c) Each operator shall provide line marking at locations where the line is above ground in areas that are accessible to the public.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-63, 63 FR 37500, 07-13-1998
Interpretation Summaries	**Interpretation: PI-91-010 Date: 04-02-1991** The type or size of marker is not specified in the regulation, but is left to the operator's discretion provided the objectives of the rule - to warn others of the presence of underground pipelines and to provide an emergency telephone number - are carried out. Although the flush markers may technically be permissible under the pipeline safety regulations, we do not encourage their use because they can become obscured by snow, debris, or vegetation. The most effective alternative would be an above ground marker that conveys the required information, but in an aesthetically pleasing manner. **Interpretation: PI-74- 0140 Date: 10-07-1974** This responds to your letter of June 21, 1974, concerning the practice of marking pipelines installed in a common trench. You state that four pipelines (both liquid and gas pipelines) are in the trench which varies in width from 6 to 10 feet. Currently,

	markers are installed at each edge of the trench so that a pipeline is no more than 5 feet away from a marker. You ask whether this practice complies with 49 CFR 195.410. Section 195.410(a) requires carriers to place and maintain line markers "over each" buried liquid line at certain locations. From the information you have provided, it is unclear whether a marker is "over each" liquid line. The only pipelines which would be marked as required are the ones at each side of the trench, but you do not state whether these lines carry liquid or gas. Any liquid line which lies in between the pipelines at each side of the trench does not have a marker over it, and consequently, is not marked in accordance with section 195.410(a). Moreover, neither the existing nor the proposed line marking, signs display the word "petroleum" or name the commodity transported, as required by §195.410(a)(2). **Interpretation: PI-73-0121 Date: 06-06-1973** Direction of flow does not need to be shown on a line marker. **Interpretation: PI-73-0104 Date: 03-10-1973** This refers to your correspondence dated December 4, 1972, concerning pipeline markers at the residence of Stephen P. and Evelyn V. Stimac. With exceptions not here pertinent, Section 195.410(a) specifically provides that a marker shall be placed ". . . over each buried line. . ." Therefore, you are correct in your interpretation. When we stated in our previous letter that the Federal regulations on line markers afford necessary flexibility to the carrier in his method of compliance, we had reference to such things as vertical positioning, overall size, or height of markers which are not wavered by the regulations. We were not suggesting that you develop a marking policy that did not comply with Section 195.410. The safety objective will not be met if you are allowed to mark multiple lines with only one line marker. Therefore, we do not agree that using a single marker over multiple lines in residential areas such as the Stimacs' is an acceptable solution.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	49 USC 60134 State Damage Prevention 49 USC 60114 One Call
Guidance Information	1. The operator must have written procedures for placing and maintaining pipeline markers. 2. Install line markers for each pipeline that crosses or lies in close proximity to any high-risk area where the potential for future excavation or damage is likely such as: a. Flood zone areas

b. Irrigation ditches and canals subject to periodic excavations for cleaning out or deepening
c. Drainage ditches subject to periodic grading, including those along roads
d. Agricultural fields subject to deep plowing or where deep-pan breakers are employed
e. Active drilling or mining areas
f. Fence lines, notable changes in direction if practicable
g. Exposed pipe including wash outs and spans, in areas accessible to the public.

3. The operator must have pipeline markers in adequate quantity so that the route of the pipeline can be accurately known. Land under cultivation, swamps, and commercial areas with significant numbers of buildings and paved areas may present practical exceptions to enforcement of basic pipeline marking requirements but the operator must show that installation of basic markers is impractical in any location where line markers are not installed as described above.
4. Line markers are required when the pipeline becomes exposed by design or through acts of nature (erosion by wind or water), in areas accessible to the public. Some examples of areas that are still considered accessible to the public include: remote areas, barbed wire fences around properties, and cow gates.
5. Ongoing construction projects near or on the pipeline may require more frequent verification that markers are in place (see Damage Prevention Guidance - §195.442).
6. Letters on the marker should be about 1" high with approximate ¼ inch stroke, and easily readable.
7. Above ground valves must be identified by a line marker in an area accessible to the public.
8. Stickers, if permanently affixed and fully legible, must be applied as soon as practicable, but within six months, over outdated information; however, the telephone number must reach the pipeline operator at all times.
9. Multiple pipelines in the same ROW shall be individually marked.
10. Operators should ensure that the line is sufficiently marked so that the use of normal methods of observation to see if markers are present from an existing marked location is adequate to discern the location of the pipeline.
11. Final Order Guidance:
    a. **Magellan Pipeline Company, LP [4-2012-5010] (September 2, 2014):** Since §195.410 requires markers to be placed "in sufficient number along the [pipeline] so that its location is accurately known," inspectors must be able to use normal methods of observation, such as walking and observing in all directions to discern the location of the line markers.CO/CP
    b. **Kinder Morgan CO2 Company, LP [4-2006-5003] (October 12, 2010):** While many operators use the so-called “line of sight” test in determining whether a sufficient number of line markers are placed over buried lines, many other do not. Section 195.410 does not expressly require that line-of-sight be maintained.

Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The route of the pipeline cannot be determined in a specific area by observation of the pipeline markers, except in areas where impracticable due to land use. 4. The line markers are not located over the pipeline. 5. Excessive vegetation covering the line markers. 6. Multiple pipelines in the same ROW do not have line markers over each pipeline. 7. The information on the marker does not include all the required elements or the letters on the marker cannot be easily read. 8. Markers are not installed at above-ground or exposed piping. 9. The information on the marker is not entirely correct. 10. The listed telephone number does not reach the pipeline operator, or their contracted service provider, at all times. 11. If the pipeline location cannot be discerned from a known marked location by observation in all directions, the pipeline has an insufficient number of line markers to identify its location. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Photos showing the pipeline right-of-way where markers should be placed. 2. Photos of incorrect information, or other similar problems. 3. Photographs that show the date the picture was taken on the picture. 4. Copies of company drawings or procedures indicating the policies and practices relative to marking their pipelines. 5. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.412
Section Title	Inspection of Rights-of-way and Crossings Under Navigable Waters
Existing Code Language	(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate mean of traversing the right-of-way. (b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-52, 59 FR 33388, 06-28-1994
Interpretation Summaries	**Interpretation: PI-01-0100 Date: 01-29-2001** You argue that the St. Joseph River in Michigan should not be characterized as commercially navigable for purposes of the National Pipeline Mapping System (NPMS) because, according to U.S. Coast Guard charts, barge traffic cannot ascend the river beyond the main street bridge in the town of Benton Harbor, approximately 1.3 miles upstream front the mouth of the river. You also note that an OPS interpretation of 49 CFR § 195.412 (March 8, 1994) defines navigable as waterways which have been designated as being navigable by the USCG in 33 CFR Subpart 2.05-25(a). As discussed in our Final Rule on reporting of underwater abandoned pipeline facilities (September 8, 2000, 65 FR 54440) the National Waterways Network (NWN) database is the basis we use to identify commercially navigable waterways. Our use of this database replaces the use of the referenced USCG designation. Upon receipt of your letter, we checked with the Waterborne Commerce Statistics Center, US Army Corps of Engineers (COE) to determine if there were any updates affecting the St. Joseph River. The COE confirmed that the waterway is considered commercially navigable and that it will be included in the next annual release of the National Waterways dataset in March of 200l. Therefore, we will continue to regard this river as commercially navigable under the published classifications. We realize that at any given time there may be hazards on a waterway which could interfere with navigation on a particular segment of a listed river. However, in order to maintain national consistency we will continue to rely on the COE National Waterways Dataset. **Interpretation:** PI-00-0102 **Date: 09-22-2000** Reply to Mayor of Piscataway, NJ that the removal of trees in that city by a pipeline operator is a matter of agreement between local officials, landowners, and the operator.

Interpretation: PI-95-0103 Date: 12-19-1995

This is in reply to your letter requesting clarification of the term "navigable waterways". As you correctly stated, the term is applied differently in the sections of 49 CFR. This is due to the statutory requirements of different implementing legislations.

Under the Oil Pollution Act, navigable waterways are considered to be not only those waters which are used for commercial navigation, but also those waters which unite with or feed into waters which are used for commercial navigation. This definition is broadly constructed because it implements a requirement to protect the waters from pollution caused by oil spills.

Under the Pipeline Safety Acts, navigable waters are considered to be waters which are, in fact, used for commercial navigation. This definition is more narrowly constructed because it implements a requirement to prevent collisions between vessels and pipelines.

Therefore, a waterway could be considered a "navigable waterway" under 49 CFR Part 194 (the regulations implementing the Oil Pollution Act) and not considered a "navigable waterway" under Part 195 (the regulation implementing the Pipeline Safety Acts). You stated in your letter that no crossing in your area meets the criteria established for Part 195 which is described in 33 CFR Subpart 2.05. If this is the case, the provisions of § 195.412(b) "inspection of rights-of-way and crossings under navigable waters" would not apply.

The provisions of Part 194 could apply to your intermittent stream crossings if those streams meet the definition of Part 194 or if they unite with waters meeting the definition of Part 194 when they contain run-off.

Interpretation: PI-92-0100 Date: 02-07-1992

We consider the use of divers to probe with rods along the length of the crossing to be an acceptable method of inspection for all underwater crossings. The divers can visually check any uncovered portions of the crossing for damage or for potential damage from drifting debris, such as logs or rocks. For covered portions, the divers can note the depth of burial or that the depth exceeds the rod length. From this information, an operator can decide if the crossing needs repair, or if it needs additional protection against reasonably anticipated external forces.

Interpretation: PI-80-0105 Date: 11-14-1980

You have asked whether indirect techniques, such as side-scanning sonar, are acceptable for locating underwater pipelines.

Underwater pipeline inspections are required by 49 CFR 195.412(b) to determine the condition of pipelines crossing navigable waterways. The purpose of the inspections is to check for conditions that could endanger safe pipeline operations, such as washouts above or below the pipeline. Although identifying a pipeline's alignment or location with respect to the river bottom, which the indirect techniques

	you have described seem capable of doing under favorable conditions, is a condition to examine under Section 195.412(b), it is not the only condition to consider. The inspection method must also be capable of detecting other problems, such as below-grade washouts and physical damage to the pipeline or coating. Thus, while the indirect techniques would be of value in making the required inspections, they are not sufficient to furnish all the information needed to comply with Section 195.412(b). For full compliance, they would have to be complemented by direct observational techniques. **Interpretation: PI-74-0122 Date: 07-02-1974** We believe flights as high as 500 feet are low enough to satisfy the inspection requirements of §195.412(a). Where a closer inspection is necessary but may not be made by aircraft under Federal Aviation Regulations, an alternative means of inspection should be used. **Interpretation: PI-73-037 Date: 11-16-1973** An acceptable inspection should with reasonable reliability determine the condition of the crossing. The inspection of these crossings should, as a minimum, determine if there is still cover on the pipeline, and, where it is determined that the pipeline is uncovered, whether there is debris or other objects hanging on it that would make the pipeline crossing precarious. A record of each inspection of a waterway crossing will be required and each company should compare the most recent inspection with previous inspections for any changes in crossing conditions. This record together with a record of any remedial or repair action taken to correct an unsatisfactory condition must be kept for the useful life of the pipeline.

Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-04-03, Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities** RSPA/OPS is issuing this advisory bulletin to owners and operators of gas and hazardous liquid pipeline systems on the potential for unauthorized excavations and the unauthorized installation of acoustic monitoring devices or other data acquisition devices on pipeline facilities. These devices are used by entities that hope to obtain market data on hazardous liquid and gas movement within the pipelines. Recent events have disclosed that devices were physically installed on pipelines without the owner's permission. Operators must control construction on pipeline right-of-ways and ensure that they are carefully monitored to keep pipelines safe. This is in line with our efforts to prevent third-party damage as reflected by our support of the Common Ground Alliance, which is a nonprofit organization dedicated to shared responsibility in damage prevention and promotion of the damage prevention Best Practices. This advisory bulletin emphasizes the need to ensure that only authorized and supervised excavations are undertaken along the nation's pipeline systems. **Advisory Bulletin ADB-97-03, Potential Soil Subsidence on Pipeline Facilities.** Heavy rainfall and flooding have increased the potential for damage to pipeline facilities. Several accidents have occurred on natural gas transmission facilities that appear to be related to the stress of soil movement on the facilities. Accordingly, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) is advising operators of pipeline facilities of the need for caution associated with excessive flooding and soil movement. In particular, pipeline operators should conduct training, and patrol their rights-of-way to identify areas of potential soil subsidence that could adversely affect the safe operation of their pipelines. Additionally, emergency plans should be reviewed to assure they adequately address conditions possible in areas of soil subsidence.
Other Reference Material & Source	
Guidance Information	1. The operator must have written procedures for the inspection of rights-of-ways and crossings under navigable waters. 2. The patrol program to observe surface conditions on and adjacent to the transmission line ROW for indications of leaks, construction activity, and other factors affecting safety and operation should include the following: a. Indication of leaks may include dead vegetation, product, sheen or bubbles on the water, and/or odor. b. Indication of construction activity may include clearing of trees or vegetation, heavy equipment including directional drilling on or near the ROW. c. Dredging activities on a waterway in the ROW crossing vicinity, a building, fence or shed, on or near the ROW. d. Presence of a coffer dam or bell hole on the ROW, or the presence of marking flags, ribbon, or paint on or near the ROW. e. Areas of continual earth moving activities (i.e. gravel/sand pits, quarries, landfills, etc.). f. Storage of material on ROW.

	g. Evidence of unauthorized ROW activities e.g., logging, out buildings, fences. h. Pipe spans, bank or shoreline erosion at water crossings, and removal of rip rap. i. Landslides, flooding, exposed pipe, subsidence. j. Dumping or burying of trash on ROW. k. Damaged or missing pipeline markers. l. Trees or vegetation obscuring the ROW. 2. An operator may select any or several of the different types of patrolling of their pipelines and facilities (walking, driving, air, or others). 3. The pipeline right-of-way conditions must be maintained as appropriate at a level that is appropriate for the type of patrol chosen. If excessive vegetation is covering the ROW, the operator shall drive or walk these areas until the ROW is cleared. 4. As indicated in the waiver of 05-17-02, in the absence of a recognized standard on bored (or drilled) crossings the current rule requiring inspections at intervals not exceeding 5 years applies to bored crossings. The initial depth of the crossing is a factor to consider in deciding what inspection methods to use and how rigorously to inspect the crossing. The interpretation supersedes the exemption to the 5-year inspection interval implied in the response to the 04-12-96 waiver request. 5. The use of the Corp of Engineers' or any other government agency's bottom profile of a river may be an acceptable inspection method if the profile specifically covers the area of the crossing from bank to bank and is within the allowed 5-year time frame. 6. The specific requirement for an underwater pipeline crossing inspection needs to be based on actual commercial water traffic in that area. 7. Final Order Guidance: a. ***Texas Eastern Pipeline Products Company* [2-2005-5013] (Apr. 13, 2006):** "The patrolling of right-of-ways is essential to help identify potential problems which could develop from third party activities along the pipeline. Patrolling is also crucial for leak detection." The surface conditions of the right-of-way and adjacent areas cannot be inspected by aerial patrolling if those areas are obstructed by an overhanging tree canopy. CP
Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The maximum interval between patrols is exceeded. 4. The minimum number of patrols was not completed within the required time frame. 5. The underwater navigable river crossing was not inspected or the maximum time interval between inspections was exceeded. 6. Construction, vegetation growth, washouts, encroachments, etc. were not detected and reported. 7. For aerial patrols, tree canopy and vegetation overgrowth not adequately trimmed, inhibited the ability to evaluate surface conditions. 8. When the route of a surface patrol does not provide adequate observation of the ROW. 9. The patrol program fails to promptly communicate critical patrol intelligence to assure the safe operation of the pipeline.

	10. Inadequate documentation of patrol follow-up activities, including dates. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Copies of the operator patrolling procedures. 2. Copies of inadequate documentation of patrol follow-up activities. 3. Copies of supporting documents showing the missing inspection or inspection interval that has been exceeded. 4. Photos showing the condition of the right-of-way at a specific location, with dates. 5. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.413
Section Title	Underwater Inspection and Reburial of Pipelines in the Gulf of Mexico and its Inlets
Existing Code Language	(a) Except for gathering lines of 4½ in (114.3 mm) nominal outside diameter or smaller, each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in water less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in affect August 10, 2005. (b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in water less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. (c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall - (1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802 of the location, and, if available, the geographic coordinates of that pipeline; (2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and (3) Within 6 months after discovery, or not later than November 1 of the year that the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation (i) An operator must show engineered alternatives to burial that meet or exceed the level of protection provided by burial. (ii) If an operator cannot obtain required state or Federal permits in time to comply with this section, it must notify OPS; specify whether the required permit is State or Federal; and justify the delay.
Origin of Code	Original Code 195-47, 56 FR 63764, 12-05-1991
Last Amendment	Amdt. 195-82, 69 FR 48400, 08-10-2004
Interpretation Summaries	**Advisory Bulletin ADB-2015-02, Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes** All owners and operators of gas and hazardous liquid pipelines are reminded that pipeline safety problems can occur from the passage of hurricanes. Pipeline operators are urged to take the following actions to ensure pipeline safety:

	1. Identify persons who normally engage in shallow-water commercial fishing, shrimping, and other marine vessel operations and caution them that underwater offshore pipelines may be exposed or constitute a hazard to navigation. Marine vessels operating in water depths comparable to a vessel's draft or when operating bottom dragging equipment can be damaged and their crews endangered by an encounter with an underwater pipeline. 2. Identify and caution marine vessel operators in offshore shipping lanes and other offshore areas that deploying fishing nets or anchors and conducting dredging operations may damage underwater pipelines, their vessels, and endanger their crews. 3. After a disruption, operators need to bring offshore and inland transmission facilities back online, check for structural damage to piping, valves, emergency shutdown systems, risers and supporting systems. Aerial inspections of pipeline routes should be conducted to check for leaks in the transmission systems. In areas where floating and jack-up rigs have moved and their path could have been over the pipelines, review possible routes and check for sub-sea pipeline damage where required.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin, ADB-11-05, Potential for damage to Pipeline Facilities Caused by the Passage of Hurricanes.** All owners and operators of gas and hazardous liquid pipelines are reminded that pipeline safety problems can occur by the passage of hurricanes. Pipeline operators are urged to take the following actions to ensure pipeline safety: 1. Identify persons who normally engage in shallow-water commercial fishing, shrimping, and other marine vessel operations and caution them that underwater offshore pipelines may be exposed or constitute a hazard to navigation. Marine vessels operating in water depths comparable to a vessel's draft or when operating bottom dragging equipment can be damaged and their crews endangered by an encounter with an underwater pipeline. 2. Identify and caution marine vessel operators in offshore shipping lanes and other offshore areas that deploying fishing nets or anchors and conducting dredging operations may damage underwater pipelines, their vessels, and endanger their crews.

Other Reference Material & Source	Final Rule Preamble: Fisheries Institute suggested the following inlet waters list based on known fishing areas (not an exhaustive listing): 1. Fresh Water Bayou/Inter- coastal Waterway to Calcasieu River, Cameron, La. 2. Calcasieu Pass, Cameron, Louisiana. 3. Intercoastal Waterway to Morgan City, Louisiana. 4. South West Pass across Vermillion Bay, Intercoastal City, Louisiana. 5. Fresh Water Bayou, Intercoastal City, Louisiana. 6. Houma Navigation Channel/Intercoastal Waterway to Bayou Chene, Morgan City, La. 7. Houma Navigation Channel through Grand Calliou Bayou/Calliou Lake, DuLac, La. 8. Houma Navigation Canal through Cat Island Pass, DuLac, Louisiana. 9. East Pascagoula River, Moss Point, Mississippi. 33 CFR Part 64 Title 33--Navigation and Navigable Waters CHAPTER I--COAST GUARD, DEPARTMENT OF TRANSPORTATION PART 64--MARKING OF STRUCTURES, SUNKEN VESSELS AND OTHER OBSTRUCTIONS
Guidance Information	1. The required procedure (§195.413(a)) to identify pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet deep mean low water is an ongoing periodic requirement to review and update. 2. The NRC reporting requirements and subsequent remediation for the discovery of a GOM/inlet offshore pipeline condition at any time after the required survey in waters less than 15 feet deep that poses a hazard to navigation is a continuing requirement. 3. Notification to the NRC is required, even though the condition does not meet the NRC leak reporting criteria. 4. Periodic inspection of underwater pipelines should be based upon the operator's procedures. The operator's procedure should have a risk-based analysis, including supporting documentation that indicates an interval for performing these periodic inspections, based on all relevant factors (e.g., the construction methods used and initial burial depth, the prevailing soil characteristics and erosion rates and the effects of hurricanes, waves, tidal forces, and vessel traffic) to each pipeline. Underwater pipelines should be inspected based upon operator procedures unless the operator can show compelling documentation why an inspection of the pipeline is not required. An example would be a horizontal drilled river/bay crossing that has the pipe with an original cover of 20 feet in a water crossing area that has low water flow velocities and minimum bank and bottom scouring. 5. The operator must show engineered alternatives provides adequate level of protection in lieu of burial.

Examples of a Probable Violation or Inadequate Procedures	1. The operator has not prepared a listing of all pipelines requiring underwater inspection and a procedure for determining when these inspections shall be conducted. The procedures must be in effect August 10, 2005. 2. The operator does not perform its operational/engineering review of pipelines requiring underwater inspection based upon the operator's procedures. Underwater pipelines shall be periodically inspected based upon the operator’s procedure measures. 3. An operator after discovering that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, as result of an inspection under paragraph (a and b) of this section, or upon notification by any person, the operator has not complied with any of the following: a. Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, of the location and, if available, the geographic coordinates of that pipeline; b. Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and c. Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year the discovery is made, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation. (An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial.) 4. Markings are not in accordance Coast Guard requirements of 33 CFR Part 64 Title 33. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. No operator procedures for performing operational/engineering analysis of the appropriate underwater pipelines. 2. No initial identification or ongoing updates of underwater pipelines that should be evaluated and inspected based upon this code requirement. 3. No documentation or records available to support that the initial underwater survey was required (all offshore pipelines in water exceeding 15 feet in depth), or that a required periodic survey was conducted. 4. No NRC report on file or a NRC report indicating that they were not promptly notified within 24 hours of discovery of an exposed underwater pipeline or that it poses a hazard to navigation. 5. The discovered offshore pipeline not meeting the minimum cover requirement §195.413(c)(3), was not marked (buoys) in accordance with §195.413(c)(2) requirements, and/or at the ends and within the required minimum distance intervals.

	6. No documentation or records available to support that reburial of the pipeline was performed as required §195.413(c)(3) or that the operator has not obtained a waiver from PHMSA.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.420
Section Title	Valve Maintenance
Existing Code Language	(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times (b) Each operator shall, at intervals not exceeding 7 1/2 months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly. (c) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969.
Last Amendment	Amdt. 195-24, 47 FR 46850, 11-22-1982.
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-02-03, Gas and Hazardous Liquid Pipeline Mapping** The Research and Special Programs Administration's (RSPA) Office of Pipeline Safety (OPS) is issuing this advisory to gas distribution, gas transmission, and hazardous liquid pipeline systems. Owners and operators should review their information and mapping systems to ensure that the operator has clear, accurate, and useable information on the location and characteristics of all pipes, valves, regulators, and other pipeline elements for use in emergency response, pipe location and marking, and pre-construction planning. This includes ensuring that construction records, maps, and operating history are readily available to appropriate operating, maintenance, and emergency response personnel. RSPA urges every pipeline operator to (1) accurately locate and clearly mark on company maps and records key pipeline features and other information needed for effective emergency response; (2) keep these maps and records up-to-date as pipeline construction and modifications take place; (3) ensure that its personnel are knowledgeable about the location of abandoned pipelines and to keep data on their location in order to further eliminate confusion with active pipelines during construction or emergency response activities; and (4) communicate pipeline information and maps to appropriate operating, maintenance, and emergency response personnel. Operators are also encouraged to collaborate with the Common Ground Alliance and the Federal and State pipeline safety programs to improve all phases of underground facility damage prevention, including improved mapping standards; and to work toward developing and using, to the maximum feasible extent, consistent mapping symbols and notational systems. **Alert Notice ALN-89-02, Each operator should test check valves.**

	The purpose of this Alert Notice is to advise you of the results of an investigation conducted by OPS of a recent pipeline accident and the relevance of that investigation to the safe operation of check valves. With this notice, OPS is alerting each gas transmission operator and hazardous liquid pipeline operator of the need to test check valves located in critical areas to assure that they close properly.
Other Reference Material & Source	
Guidance Information	1. All mainline valves are necessary for the safe operation of a pipeline system. In addition to mainline valves, other valves are necessary for the safe operation of a pipeline. 2. The operator must be able to identify (list) all valves on its system that are necessary for the safe operation of their pipeline, including mainline valves. 3. The operator must inspect and partially operate all mainline valves within the required time intervals. 4. The operator must have records showing that all valves necessary for the safe operation of its pipeline system have been maintained. 5. Maintenance discrepancies identified during valve inspections must be addressed and remedial actions documented. 6. Valves installed after October 4, 1969 must have an indicator, to clearly show the valve position as required in §195.116(e). 7. Mainline valve inspection/testing records shall identify the individual who did the valve inspection, the date the valve inspection occurred, which valve items were inspected and or tested to determine it was functioning properly, the condition of those valve items inspected and or tested, resolution of valve items found to be deficient. 8. Some mainline valves may be equipped with a thermal relief valve from the manufacturer to protect the valve body from thermal expansion when the valve is shut in. This relief valve must be inspected. This inspection, per the operator's procedures or manufacturer's recommendations, can be done with the mainline valve inspection required here, or done on a separate inspection schedule just for the reliefs. (See 195.428). 9. Maintenance records for all valves necessary for the safe operation of a pipeline must show that the valve was maintained adequately, using the operators' procedure, the manufacturer's recommendations, or some combination thereof. 10. Procedures for maintaining all valves necessary for the safe operation of a pipeline must describe in adequate detail how valves are to be maintained. This could be a company procedure or it could reference the manufacturer's recommended maintenance practices. 11. Procedures for inspecting mainline valves must describe in detail how mainline valves will be inspected to ensure they are functioning properly. Procedures shall include more than just partially operating a valve, including valve maintenance items, such as dewatering and winterization of valves as appropriate. Often part of the procedure is a checklist of specific items following the manufacturer's recommendations to be used by personnel in performing the inspections. Dewatering and winterization of valves as appropriate

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<td>12. Procedures must address how deficiencies found during valve inspections will be handled.
13. Valves need to be in a secure area to prevent tampering and vandalism or locked.
14. An operator should determine the security requirements needed for their valves.
15. Final Order Guidance.
a. BP Pipelines (North America) Inc. [3-2006-5027] (November 7, 2007) – Found that operator had valves that did not operate at the time of an inspection because of the intrusion of water that had frozen. The operator argued at hearing that the valves had been inspected at the required intervals in accordance with their procedures, and that these valves were inoperable at the time of the inspection, but the valves were on a line that was not in-service at the time of the OPS inspection. The Final Order found the operator in violation. CP

b. Kinder Morgan C02 Logistics Operations. L.P. [4-2006-5003] (October 12, 2010) – Found that the operator had a large number pipeline valves that did not have fencing around them. Many of the operator’s valves had pipe post and beam enclosures, which might keep cattle from rubbing against the valves and piping but would not discourage vandalism. An operator must use appropriate protective measures to prevent unauthorized operation or vandalism of their valves. The operator alleged to have performed a security study to determine where fencing was needed but provided no documentation. The CO required the operator to perform a security study of its valves and take appropriate actions to correct those locations the study found to have deficient valve protection. CO

c. Cenex Pipeline Company [5-2001-5003] (February 10, 2003) – Found that the operator did not have records to show that they had inspected and tested 48 mainline valves. Operator argued that there is no clear definition in Part 195 for a mainline valve. In the Final Order, mainline valves were defined as valves integral to the safe operation of the pipeline system such as those used for station isolation, segment isolation, water crossing isolation, and lateral isolation. CP

d. BP Oil Pipeline 3-2009-5009 (June 14, 2011) Certain valves could only be closed slightly with "tremendous efforts" and did not operate freely when reopened. The difficulty in operating the valves demonstrates the valves were not "in good working order," as the regulation requires. In the event of an emergency, Respondent's valves would not have been in a condition to be rapidly closed by hand to mitigate the consequences of a pipeline release.[7] Even though Respondent had performed maintenance on the valves at six-month intervals, PHMSA determined that BP had violated the regulatory standard because the valves were not in good working order at the time of the inspection. CP</td>
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<td>Examples of a Probable Violation or Inadequate Procedures</td>
<td>1. The lack of procedures is a violation of 195.402.
2. The lack of records is a violation of 195.404.
3. Operator did not identify mainline valves or other valves necessary for the safe operation.
4. Operator did not maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.</td>
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	5. Mainline valve inspections were not performed at the minimum required intervals. 6. Operator did not provide security for each valve necessary for the safe operation of its pipeline from unauthorized operation and vandalism. 7. Operator did not follow their procedures. 8. Valve inspection and maintenance records do not contain specificity to determine one or more of the following 1) who did inspection and maintenance, what was inspected, what maintenance was performed, and what was found. A valve necessary for the safe operation of a pipeline is observed to be inoperative regardless of the operating status of the pipeline. (CPF 3-2006-5027) *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. O&M Manual procedures. 2. Operator's personnel statements. 3. Records identifying mainline and other valves needed for safe operation. 4. Inspection records 5. Maintenance records. 6. Manufacturer's maintenance recommendations. 7. Photos of valves in regard to maintenance, position indicator, and security issues. 8. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.422
Section Title	Pipeline Repairs
Existing Code Language	(a) Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property. (b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-22, 46 FR 38357, 07-27-1981.
Interpretation Summaries	**Interpretation: PI-10-0013 Date: 11-18-2010** PHMSA regulations do not limit the number of discrete applications of an alternative repair method. The engineering test data for the proposed material must clearly demonstrate that the alternative repair method will restore the original design strength of the pipe, and perform in the pipeline environment in which it is installed, including withstanding secondary stresses of loading, pipe movement, soil movement, and external loads, for the length of service for which it is intended. While the rule allows alternative repair methods for individual repairs on corroded or damaged steel pipe in natural gas pipelines or corroded steel pipe in hazardous liquid pipelines where appropriate, an operator of a pipe joint with sufficient defects should carefully consider all reliable methods of repair before installing an excessive number of alternative repairs. No repair method can be used to increase the original design strength or the pressure of a segment of pipeline above the established maximum operating pressure. **Interpretation: PI-92-054 Date: 10-05-1992** This responds to your letter of August 24, 1992. You asked if mechanical connectors are acceptable for use in the repair of underwater pipelines under 49 CFR Parts 192 and 195. Parts 192 and 195 do not prohibit the use of mechanical connectors in the repair of gas, hazardous liquid, or carbon dioxide underwater pipelines. However, an operator's use of mechanical connectors is subject to applicable sections of the regulations. **Interpretation: PI-86-006 Date: 08-21-1986** Your letter of July 16, 1986, requests that we amend Part 195 to permit the use of encirclement sleeves as a repair method for defective welds in operating pipelines. Your letter indicates that ANSI B31.4 permits their use as an acceptable repair method in either maintenance or construction.

	The regulation governing the repair of hazardous liquid pipelines in operation is §195.422. Encirclement sleeves can be used to repair defects in operating pipelines, including weld defects. Part 195 does not, however, permit the use of encirclement sleeves to repair weld defects discovered during construction. These defects must be removed or repaired in accordance with the requirements of §195.230.
Advisory Bulletin/Alert Summaries	**Advisory Bulletin ADB-13-04, Notice to Operators of Hazardous Liquid and Natural Gas Pipelines of a Recall on Leak Repair Clamps Due to Defective Seal** PHMSA is issuing an Advisory Bulletin to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. Operators with TDW LRCs should discontinue use immediately and contact TDW for further recall instructions. **Advisory Bulletin ADB-10-03, Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe** PHMSA is issuing an advisory bulletin to notify owners and operators of recently constructed large diameter natural gas pipeline and hazardous liquid pipeline systems of the potential for girth weld failures due to welding quality issues. Misalignment during welding of large diameter line pipe may cause in-service leaks and ruptures at pressures well below 72 percent specified minimum yield strength (SMYS). PHMSA has reviewed several recent projects constructed in 2008 and 2009 with 20-inch or greater diameter, grade X70 and higher line pipe. Metallurgical testing results of failed girth welds in pipe wall thickness transitions have found pipe segments with line pipe weld misalignment, improper bevel and wall thickness transitions, and other improper welding practices that occurred during construction. A number of the failures were located in pipeline segments with concentrated external loading due to support and backfill issues. Owners and operators of recently constructed large diameter pipelines should evaluate these lines for potential girth weld failures due to misalignment and other issues by reviewing construction and operating records and conducting engineering reviews as necessary. **Alert Notice ALN 87-01, Incident involving the fillet welding of a full encirclement repair sleeve.** The Office of Pipeline Safety strongly recommends that all operators who have fillet welded any items to a high pressure carrier pipe, review their welding procedures used to make fillet welds. Operators whose fillet welding procedures are similar to those described above should immediately discontinue this procedure. Operators who have used a similar fillet welding procedure in the past may want to consider a field inspection program of the fillet welds to determine if cracks have developed in

	the HAZ and to take appropriate action. The Fluorescent Magnetic Wet Particle Examination method performed in accordance with ASME Section V, Article 7, has proven to be an accurate method in determining if underbead cracking has occurred.
Other Reference Material & Source	Pipeline Repair Manual, PRCI, August, 2006. ASME/ANSI B31.4–2006, ‘‘Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids’’ (see 195.3 for current Incorporated by reference version) . API Standard 1104, ‘‘Welding of Pipelines and Related Facilities’’ (see 195.3 for current Incorporated by reference version) (20th edition, October 2005, errata/addendum (July 2007), and errata 2 December 2008)), Appendix B, In-Service Welding. API 1160, “Managing System Integrity for Hazardous Liquids Pipelines”, November 2001.
Guidance Information	1. Operator shall have and follow written procedures for all repairs as per §195.402. 2. Precautionary safety measures addressed by the written procedures may include: a. Lower pressure for pipe assessment and welding b. Take line out of service for major repair or cutout c. Purge line of hazardous product for major repair or cutout d. Appropriate pipe support e. Ditch/bell hole stabilization or adequate shoring f. Prevention of over pressuring of blind flanges/skillets g. Application of lockout/tag out procedures h. Implementing isolation via double block and bleed i. Appropriate pressure containment considerations j. Hot work restrictions k. Hazardous gas, fumes or vapor testing and adequate ventilation l. Provisions for firefighting equipment and protective clothing 3. All repairs must be documented. Documentation may include location, damage or anomaly descriptions, remaining strength calculations, material specifications, locations, pictures, NDT, site specific procedures, personnel qualifications, test records, welding procedures, and other pertinent information. This information must be retained for the active life of the pipe. 4. The PRCI Pipeline Repair Manual (not invoked in Part 195), Section 451.6.2(c) of ASME B31.4 and API 1104 19th Edition, Appendix B, In-Service Welding can provide further guidance to determine if repair methods used on line pipe have been done in a safe manner. 5. If the pipeline is to be repaired without taking it out of service, the operating pressure during the repair must be monitored to insure a safe pressure during the repair process. 6. UT examination of the repair area should be performed immediately prior to the intended repair work to assure safe working conditions. 7. Appropriate NDT methods must be used after the repair to evaluate the integrity of the repair.

8. Alternatives to composite pipe wrap type repair should be considered on above-grade piping where there is a possibility of fire hazards and UV degradation.
9. Composite pipe wraps can be used for pipe reinforcement repairs but they cannot be used on defects that go through the pipe wall.
10. Operator should remove stress risers prior to application of composite sleeve material, and ensure that all cracks are removed.
11. The operator is responsible for ensuring the personnel installing composite wrap must be trained by the manufacturer of the composite pipe wrap.
12. Records for welding repairs must meet the requirements of §195.404(c) (1), and include who performed the repair, the procedure for the repair, and indicate the qualified welder and welding procedure.
13. The description of repairs involving welding must document a method of non-destructive testing to verify the integrity of the weld(s).
14. The description of repairs involving composite sleeve material must document the type of sleeve material used, and the qualified personnel involved in the repair.
15. Pipe repair accomplished by grinding must include a site-specific grinding plan which includes the limits of metal removal, methods of testing post grinding to determine the condition of the pipe, remaining wall thickness, and the personnel performing the repair.
16. Pipeline repairs must meet construction requirements for depth of cover except for repairs where, due to the length, it is impractical.
17. Final Order Guidance:
    a. ***Texas Eastern Products Pipeline Co. [3-2005-5018] (February 27, 2009)*** – Found that the operator failed to ensure that its contractor repaired its pipeline system in a safe manner, resulting in the release of toxic butane vapors and the asphyxiation of a pipeline worker. The operator argued that the contractor was uniquely responsible for the accident, that the piping modification project in question was not a "repair" and that PHMSA could not hold it liable for the actions of the contractor without regard to fault. After noting that §195.10 makes an operator responsible for the actions of a contractor, the Final Order concluded the piping modification was a repair, that operators have an "obligation to take all practical steps to take care that work projects are conducted in a safe manner", and that TEPPCO "failed to take even basic steps" to ensure safety, i.e., it did not provide its contractor with a rescue harness, breathing apparatus, training for threat recognition and response, or appropriate supervision. CP

    b. ***Bridger Pipeline LLC. [5-2007-5003] (April 2, 2009)*** – Found that the operator made unsafe repairs when they installed approximately 100 Type B sleeves in 2005 without an evaluation method capable of demonstrating the repairs were made safely, particularly the soundness of the sleeve fillet welds. Operator argued that they had visually inspected welds but the operator had no record of those visual inspections. Operator also argued that they had hydrotested the pipeline after repairs had been completed. Final Order found that hydrotesting is not capable of testing the integrity of fillet welds on type-B repair sleeves and they were ordered to re-dig a percentage of those repairs in order to perform and document inspections and correct any deficiencies found during those inspections. CO

    c. ***BP Pipelines [3-2009-5002] (April 3, 2012)*** **–** Found that the operator failed to replace a portion of pipeline with a segment of pipe that was designed

	and constructed for that particular pipeline as required by Part 195. The operator failed to properly design and construct this replacement by selecting and installing pre-tested pipe that was not qualified based on the maximum operating pressure limitation for the remainder of the pipeline. The construction process must ensure pipe being installed is tested prior to operation at a pressure equal to 125 percent or more of MOP of the pipeline to ensure compliance with§§ 195.302 and 195.304. CP **d.** ***Enterprise Products Operating [3-2009-5022] (August 14, 2012)*** **-** Found the operator did not insure that the installation of a bypass was made in a safe manner so as to prevent damage. In this case, the record shows that the operator had no procedures in its Operations and Maintenance Manual (O&M Manual) or in the Job Plan for this specific repair (how to safely make a threaded connection). C P
Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did not follow procedures. 4. Operator failed to ensure that the repairs are made in a safe manner and to prevent damage to persons or property. Example: An operator failed to perform NDT of welds made for sleeve welds. 5. Repair method or materials not appropriate for operating pressures or condition. 6. Operator did not document the repair. 7. An accident occurs as a result of the repair process. 8. Operator repaired the pipeline with pipe segment or component not designed or constructed as required by other paragraphs of Part 195. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. O&M procedures. 2. Pipeline repair records 3. Document any statements made by the Operator's personnel in the violation report. 4. Maintenance records/reports. 5. Photos of repair location site and pipe. 6. Accident reports. 7. Lack of procedures or reports.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.424
Section Title	Pipeline Movement
Existing Code Language	(a) No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure. (b) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are joined by welding unless- (1) Movement when the pipeline does not contain highly volatile liquids is impractical; (2) The procedures of the operator under §195.402 contain precautions to protect the public against the hazard in moving pipelines containing highly volatile liquids, including the use of warnings, where necessary, to evacuate the area close to the pipeline; and (3) The pressure in that line section is reduced to the lower of the following: (i) Fifty percent or less of the maximum operating pressure; or (ii) The lowest practical level that will maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 psig (345 kPa gage) above the vapor pressure of the commodity. (c) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are not joined by welding unless- (1) The operator complies with paragraphs (b)(1) and (2) of this section; and (2) That line section is isolated to prevent the flow of highly volatile liquid
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-63, 63 FR 37500, 07-13-1998.
Interpretation Summaries	**Interpretation: PI-94-006 Date: 02-04-1994** You also asked us to interpret § 195.424(a) to exclude small movements of pipe associated with certain operation and maintenance activities, including the restoration of pipe to its original position. Section 195.424(a) states: "No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure." The plain meaning and history of this rule would not support an interpretation that small movements are excluded from the rule. However, §195.424(a) does not apply unless an operator moves pipe as a necessary step in a maintenance activity. Thus, the rule applies, for example, when pipe is lowered to accommodate a road crossing, and when displaced pipe is moved back into its original position. But the rule does not apply to movements that result from operating pressure or temperature fluctuations, because such movement is not part of a maintenance activity. Also, the rule does not apply to movement that is incidental to pipeline repair, such as movement that occurs when temporary pipe support is added or removed, or when pipe strain is relieved by excavation. Movements such as these are not a necessary part of the repair procedure.

Advisory Bulletin/Alert Summaries	**Alert Notice ALN-91-03, NTSB SR P-91-2 Texas Eastern Products Pipeline Company 02/02/90 explosion: Actions to be taken before moving pipeline.** OPS is alerting all operators of gas and hazardous liquid pipelines to conduct analyses before moving pipelines, whether or not the pipelines are pressurized at the time of movement. Failure to perform an analysis could increase the risk of failure during or after the movement with subsequent risk to public safety and damage to the environment. A recent pipeline accident and resulting NTSB report which included recommendation P-91-2 have caused OPS to reevaluate factors to be considered when the movement of a pipeline is proposed. NTSB recommendation P-91-2 would: Require pipeline operators to conduct analyses, before moving pressurized pipelines to determine: (1) the extent to which the pipe may be safely moved; (2) the specific procedures required for the safe movement of the pipe; and (3) the actions taken for the protection of the public.
Other Reference Material & Source	API-RP 1117, Movement of In-Service Pipelines, 3rd edition including errata 1 (2008) and 2 (2009), (formerly lowering in-service pipelines) Battelle Report, Guidelines for Lowering Pipelines While in Service, July 1990. Alyeska petitioned RSPA/OPS in 2004 for a waiver from compliance with the requirements of 49 CFR 195.424(a) for 420 miles of aboveground line pipe in the Trans Alaska Pipeline System (TAPS). Alyeska was subsequently granted that waiver.
Guidance Information	1. The operator must have a written site specific plan for the lowering or relocating in service pipeline. 2. This plan should include at a minimum an analysis of the following factors prior to considering the lowering of an in-service pipeline: the required deflection, the diameter, wall thickness, grade of the steel, characteristics of the pipeline, the terrain, the soil, safety, the cumulative stresses on the pipe while moving and after lowering, and the toughness of the of the steel. The plan should include sufficient details such as the calculations concerning the length of pipe that can span (unsupported) an excavation prior to lowering the pipe. 3. There should be information regarding the maximum vertical and horizontal movement (should be in steps) allowed at each stage of the lowering process. 4. Additional precautions are necessary when moving pipelines that contain HVLs. Detailed plans should include notification and possible evacuation of nearby public when moving HVL pipelines, evacuating the medium in the pipe, excavation of the pipeline and checking for coating damage during the moving process. 5. Emphasis must be placed on protecting the public, the operator’s employees, property, and the environment while accomplishing this task.
Examples of a Probable Violation or	1. The lack of a procedure is a violation of 195.402. 2. The lack of records is a violation of 195.404.

Inadequate Procedures	3. Operator did not follow written plan, document deviations from written plan, or show that removal of HVLs was impractical. 4. The written plan does not effectively address the requirements of the code section. 5. Operating pressure was not reduced to less than 50% of MOP prior to moving a pipe segment, except for HVL which must be kept at a pressure which maintains them as a liquid. 6. There was no documentation to indicate that it was impractical to evacuate the HVL from a pipeline segment prior to lowering the segment. 7. The operator did not notify residents near the pipeline prior to moving an HVL pipeline. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Site specific line pipe movement plan for the project and other pertinent information concerning the line lowering project. 2. Completed site specific line pipe movement plan implementation record including OQ qualified personnel responsible for the project. 3. Photos of the site before, during and after the project. 4. Line pipe movement procedures. 5. Records of pipeline pressures during the movement process. 6. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.426
Section Title	Scraper and Sphere Facilities
Existing Code Language	No operator may use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-22, 46 FR 38357, 07-29-1981
Interpretation Summaries	**Interpretation: PI-71-001 Date: 08-01-1971** The main purpose of Section 195.426 is to minimize the opening of end closures on scraper and sphere facilities while the facility is subjected to pressure, and thereby reducing the possibility of injury to personnel removing the end closure. There are two requirements contained in Section 195.426. One requirement is that the barrel in which the scraper or sphere is inserted or removed contains a relief device, such as a blowoff, which can be used to relieve pressure on the barrel prior to opening the end closure on the barrel. The second requirement is that the end closure itself must contain a device to either prevent the closure from being removed prior to release of the pressure on the barrel or to indicate that pressure still remains on the barrel. The "lock and bleed" device on Yale closures and the "pressure warning device" on Tube Turn closures satisfy the second requirement mentioned above. You raised the question in your June 7, 1971 letter, as to whether the above mentioned devices would satisfy the "relief valve feature" of the regulation. Section 195.426 contains the term "relief device" but not the term "relief valve." You might have been thinking of a device that would relieve pressure in the barrel automatically if it becomes as high as the preset valve on the relief valve. Section 195.426 contains no such requirement. The information that you recently provided to this department, revealed that the scraper and sphere facilities designed by your firm include a blowoff device, as previously mentioned, in addition to the "lock and bleed" device. This indicates that the Charles Wheatly Company is fulfilling the requirements of Section 195.426 in design of scraper and sphere equipment.
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	
Guidance Information	1. Closure devices that indicate to the operator that pressure remains on the barrel prior to opening the closure, such as "lock and bleed" or "pressure warning" devices, are adequate devices. 2. Valves with nipple fittings capable of accepting a pressure gauge are adequate for determining that pressure has been relieved, even if the gauge is attached only during trap operations. 3. Operator must have a written procedure for use of the launcher/receiver, including pressure relief.
Examples of a Probable Violation or Inadequate Procedures	1. The lack of a procedure is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did not follow its written procedure. 4. Operator installs or uses a launcher or receiver that is not equipped with a prescribed relief device, such as a drain valve. 5. Operator does not use a suitable, functional pressure indicating device, and does not provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Accident investigation. 2. Document any statements made by of operator's personnel in the violation report. 3. Piping and instrumentation diagram of launcher/receiver. 4. Copy of applicable procedures. 5. Photos. 6. Observation of pig launching or receiving. 7. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.428
Section Title	Over-pressure Safety Devices and Overfill Protection Systems
Existing Code Language	(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 ½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used. (b) In the case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years. (c) Aboveground breakout tanks that are constructed or significantly altered according to API Std 2510 (incorporated by reference, see § 195.3) after October 2, 2000, must have an overfill protection system installed according to API Std 2510, section 7.1.2. Other aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed or significantly altered after October 2, 2000, must have an overfill protection system installed according to API RP 2350 (incorporated by reference, see § 195.3). However, an operator need not comply with any part of API RP 2350 for a particular breakout tank if the operator describes in the manual required by § 195.402 why compliance with that part is not necessary for safety of the tank(d) After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-100, 80 FR 12781, March 11, 2015.
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-05-05, Inspecting and Testing Pilot- Operated Pressure Relief Valves** This notice announces a pipeline safety advisory bulletin about pilot-operated pressure relief valves installed in hazardous liquid pipelines. The bulletin provides pipeline operators guidance on whether their inspection and test procedures are adequate to determine if these valves function properly. Malfunctioning of a pilot-operated pressure relief valve was a contributing factor in an accident involving a petroleum products pipeline in Bellingham Washington. Operators should review their in-service inspection and test procedures used on new, replaced, or relocated pilot-operated pressure relief valves and during the periodic inspection and testing of these valves. Operators can use the guidance stated below to ensure the procedures approximate actual operations and are adequate to determine if the valves functions properly.

Other Reference Material & Source	From API-2510, "Design and Construction of LPG Installations", 8th edition, 2001: 7.1.2.4 "For tanks that cannot be removed from service, provisions shall be included for testing, repairing, and replacing primary gauges and alarms while the tank is in service". API Recommended Practice 2350, ''Overfill Protection for Storage Tanks In Petroleum Facilities''' (3rd edition, January 2005). From Amendment 195-66: An operator would be expected to follow the provisions of an API Recommended Practice, unless the operator notes in its procedural manual the reasons why compliance with all or certain provisions are not necessary for the safety of a particular break-out tank(s).
Guidance Information	1. Operator needs to have a written plan to address overpressure protection safety devices. 2. Normal operating pressure control set points may not exceed the MOP. 3. Pressure safety equipment or overpressure control equipment may be set up to 110% of the MOP as long as the equipment will prevent 110% of the MOP from being exceeded during abnormal operations or upsets. 4. Discharge pressure control valves are included in this requirement and must be inspected and tested to ensure proper set point, span, and zero of the control device. 5. Thermal relief valves, including relief valves on mainline valves, are included in this requirement and must be inspected. These valves must be inspected to the operator's inspection schedule or the manufacturer's recommendation. The operator must provide technical justification for thermal relief valves that are not on the inspection schedule. Applicable electronic control devices, such as transducers, station logic controller and communications linkage between components which act as overpressure safety devices must also be inspected and tested. 6. Records for pressure switches, transducers, transmitters, RTUs, PLCs and any other primary electronic pressure control device records that serve as pipeline overpressure protection should include: a. The device identifier. b. Date the inspection and testing was completed. c. Name of individual who performed the inspection and testing. d. The device's operational and mechanical condition. e. Design set point pressure for the device. f. As found and as left set point pressure of the device. g. Design mA to pressure span for a transducer. h. As found and as left mA to pressure span for a transducer. i. Verification of accurate mA to pressure signal from transducer to other control devices through the associated transmitter(s). 7. Equipment maintenance records for mechanical pressure relief valves (thermal relief and pressure relief valves) records should include: a. The device identifier. b. Date the inspection and testing was completed.

c. Name of individual who performed the inspection and testing.
d. Design set point pressure for the device.
e. As found and as left set point pressure of the device.
f. A check of the devices communications to associated alarms.
g. The device's operational and mechanical condition.

8. Equipment maintenance records for breakout tank overfill protection system [API 2350, App. C.1.3] should include:
   a. The device identifier.
   b. Date the inspection and testing was completed.
   c. Name of individual who performed the inspection and testing.
   d. The device's operational and mechanical condition.
   e. As found and as left alarm conditions.
   f. A check of the devices communications to associated alarms.
9. As per §195.262 overpressure safety devices installed prior to July 27, 1981 as part of the pumping equipment must be tested under conditions approximating actual operations and found to function properly before the pumping equipment may be used. Factors affecting the calculation of capacity can be derived from manufacturer data and/or direct measurement during full-flow conditions. Calculated capacity must include the effect of piping size and length associated with the relief device.
10. If calculations or determination otherwise indicates that capacity is not adequate, adjustments should be made promptly.
11. Operators with required overfill protective systems must comply with the requirements of API 2350 Sec. 4.
12. Final Order Guidance:
    a. ***BP Pipeline (North America) Inc. [4-2001-5001] (July 29, 2003)*** – Found that operator had not inspected and tested a number of thermal relief valves. Operator argued that these relief valves were redundant thermal overpressure protection and that they had a procedure to prevent sections of pipe from being isolated by leaving a valve open to an atmospheric tank. Final Order found that §195.428 applies to all relief valves that are part of the pipeline facility. CP
    b.
    c. ***Belle Fourche Pipeline [5-2009-5042] (November 21, 2011)*** Found that the operator failed to inspect and test overfill protection systems at intervals not exceeding 15 months, but at least once a calendar year. The operator did not have records to demonstrate the devices had been tested at the required intervals under the regulation. The operator argued that it could provide records of "hand gauging" the tanks every month to verify the accuracy of the levels displayed by the SCADA system. PHMSA argued respondent's hand gauging was inadequate to verify the accuracy of the overfill devices. CP, CO
    d.
    e. ***Plains Pipeline, LP [4-2012-5020] (May 17, 2013)-*** Found that while it may pose practical difficulties for a pipeline operator to ensure that breakout tanks owned and maintained by another company but used to protect the pipeline operator's facilities are properly inspected and tested under Part 195 and that such tests are properly documented, the regulation imposes an obligation on the pipeline operator to ensure that breakout tanks used to protect its system meet the requirements of §195.428. CO
    f.

g. ***Explorer Pipeline Company, [3-2013-5010M] (July 9, 2015)-*** PHMSA found that procedures were inadequate because they failed to require recording the "as found" and "as left" settings on overpressure safety devices. A performance-based regulation, such as § 195.428(a), will generally establish a minimum level of safety, which operators must meet or exceed. In this case, operators must annually determine that each pressure safety device is "functioning properly, is in good mechanical condition, and is adequate." Among other things, operators must be able to detect if the set point for an overpressure safety device is drifting because if that was occurring, the device would not be functioning properly. In addition, as prior enforcement history demonstrated, documenting the "as found" and "as left" condition of safety devices ensures compliance with this requirement. PHMSA concluded there is an important safety reason for Explorer to record "as found" and "as left" settings during inspections to ensure each overpressure safety device is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation. ODA

h.

i. ***Holly Energy Partners-Operating, L.P. [5-2012-6006] (February 6, 2014)*** *– Found that operator failed to timely inspect and test all overpressure devices once a year as covered by the requirements. The operator did not have records to demonstrate the devices had been tested at the required intervals under the regulation. Furthermore, the operator relied on pump curves that could not be validated to the current pump configuration. Regardless of ownership of equipment, operator is still required to maintain records. The regulation imposes an obligation on the pipeline operator to ensure overpressure protection meets and is documented per requirements of §195.428. CO*

j. ***Explorer Pipeline Company [3-2013-5010M] (July 9, 2015)-*** PHMSA found that procedures were inadequate because they failed to require recording the "as found" and "as left" settings on overpressure safety devices. A performance-based regulation, such as § 195.428(a), will generally establish a minimum level of safety, which operators must meet or exceed. In this case, operators must annually determine that each pressure safety device is "functioning properly, is in good mechanical condition, and is adequate." Among other things, operators must be able to detect if the set point for an overpressure safety devices is drifting because if that was occurring, the device would not be functioning properly. I addition, as prior enforcement history demonstrated, documenting the "as found" and "as left" condition of safety devices ensures compliance with this requirement. In prior enforcement cases, PHMSA has determined that documenting "as found" and "as left" settings is necessary for safe operation in compliance with §§ 195.404 and 195.428 for hazardous liquid pipelines, and §§ 192.709 and 192.739 for natural gas pipelines. PHMSA concluded there is an important safety reason for Explorer to record "as found" and "as left" settings during inspections to ensure each overpressure safety device is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation. ODA

Examples of a Probable Violation or Inadequate Procedures	1. Lack of procedures is a violation of 195.402. 2. Lack of records is a violation of 195.404. 3. Operator did not follow a written procedure for inspection and testing of overpressure devices. 4. Maintenance records do not demonstrate an adequate inspection or the inspection interval requirements were not met. 5. Pressure control or relief device not listed on operator's maintenance records. 6. Device setting is within allowable pressure, but communication to control equipment is not tested or does not function properly. 7. Pressure control or relief valve target set points are in conflict with design limitations. 8. Testing and inspection records lack specificity (see guidance above). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's written procedures. 2. Equipment maintenance records. 3. Photos of the devices in question. 4. Segment MOP listings. 5. Accident reports. 6. Pressure records. 7. Tank strapping tables. 8. Interviews with operator personnel. 9. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.430
Section Title	Firefighting Equipment
Existing Code Language	Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be-- (a) In proper operating condition at all times; (b) Plainly marked so that its identity as firefighting equipment is clear; and (c) Located so that it is easily accessible during a fire.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-22, 46 FR 38357, 07-27-1981
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NFPA 30, ''Flammable and Combustible Liquids Code'' (2008 edition, approved August 15, 2007). OSHA§1910.157, Portable Fire Extinguishers NFPA-10, Portable Fire Extinguishers
Guidance Information	1. Operators must have a documented plan to fight fires at their facilities which includes confirmation that either the operator or local firefighting organizations have adequate firefighting equipment to deal with anticipated fires. 2. Operator's procedures may address extinguisher inspection and maintenance under OSHA and/or NFPA: Generally, OSHA and NFPA require: a. Portable extinguishers …shall be visually inspected monthly. b. The employer shall assure that portable fire extinguishers are subjected to an annual maintenance check. …. c. A trained person …shall service the fire extinguishers not more than 1 year apart d. Portable extinguishers must be subjected to a hydrostatic pressure test between every 5 and 12 years depending on the agent. e. Records shall be kept on a tag or label attached to the fire extinguisher, on an inspection checklist maintained on file, or by an electronic method that provides a permanent record.

Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did not follow written procedures. 4. An operator that maintains firefighting equipment to respond to incipient fires only has not coordinated with local firefighting organizations to confirm that they have adequate firefighting equipment. These activities should include coordination meetings and the development of fire plans for responding to station and tank fires. - Firefighting equipment is nonexistent or is not properly maintained at each pump station and breakout tank area. 5. Firefighting equipment is located too far from hazard. 6. Firefighting equipment is not adequately marked or is difficult to access. 7. Operator has not established an adequate inspection program to assure: a. The equipment is in proper operating condition at all times b. The equipment is plainly marked c. The equipment is located so that it is easily accessible during a fire. 8. Records are not maintained for each fire extinguishers inspection and maintenance. 9. Records indicate that intervals for inspection and maintenance have been exceeded. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Firefighting plan 2. O&M procedures. 3. Documented statements from the Operator. 4. Maintenance records/reports. 5. Visual observation. 6. Photographs. 7. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.432
Section Title	Breakout Tanks
Existing Code Language	(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank. (b) Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel above-ground breakout tanks according to API Std 653 (except section 6.4.3, Alternative Internal Inspection Interval) (incorporated by reference, see § 195.3). However, if structural conditions prevent access to the tank bottom, its integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3). The risk-based internal inspection procedures in API Std 653, section 6.4.3 cannot be used to determine the internal inspection interval. (1) Operators who established internal inspection intervals based on risk-based inspection procedures prior to March 6, 2015 must re-establish internal inspection intervals based on API Std 653, section 6.4.2 (incorporated by reference, see § 195.3). (i) If the internal inspection interval was determined by the prior risk-based inspection procedure using API Std 653, section 6.4.3 and the resulting calculation exceeded 20 years, and it has been more than 20 years since an internal inspection was performed, the operator must complete a new internal inspection in accordance with § 195.432(b)(1) by January 5, 2017. (ii) If the internal inspection interval was determined by the prior risk-based inspection procedure using API Std 653, section 6.4.3 and the resulting calculation was less than or equal to 20 years, and the time since the most recent internal inspection exceeds the re-established inspection interval in accordance with § 195.432(b)(1), the operator must complete a new internal inspection by January 5, 2017. (iii) If the internal inspection interval was not based upon current engineering and operational information (i.e., actual corrosion rate of floor plates, actual remaining thickness of the floor plates, etc.), the operator must complete a new internal inspection by January 5, 2017 and re-establish a new internal inspection interval in accordance with § 195.432(b)(1). (2) [Reserved] (c) Each operator must inspect the physical integrity of in-service steel aboveground breakout tanks built to API Std 2510 (incorporated by reference, see § 195.3) according to section 6 of API Std 510 (incorporated by reference, see § 195.3). (d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-99, 80 FR 187, January 5, 2015;l 80 FR 46848, August 6, 2015

Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Amendment 195-66, 04-02-99 Excerpts If the referenced part of a standard, specification, or code allows or calls for the use of engineering judgment, in determining compliance with the referenced part, we will not object to the use of judgment. We will, however, compare the judgment used against what is reasonable under the circumstances. If an operator wishes to achieve a particular objective in a way that differs from the referenced part of a standard, specification, or code or falls outside the range of allowable judgment, it can request permission to do so by applying to us or the appropriate state agency, as applicable, for a waiver of the referenced part (see 49 U.S.C. 60118). Section 195.432(a) includes an exception for tanks that are subject to the other inspection requirements of Section195.432. We did not eliminate the existing annual inspection requirement as API suggested, because it provides for maintenance inspection of breakout tanks that are not subject to the new integrity inspection requirements, such as anhydrous ammonia tanks and non-steel tanks. Some tank bottoms cannot be inspected under API Standard 653 because the steel bottom has been repaired by a concrete cover. The final rule allows an operator to use an assessment technique included in its operations and maintenance manual for tank bottoms to which access is prevented by structural conditions. The references to consensus standards do not include parts of those standards that are not directly related to carrying out inspections. For example, parts of section 4 of API Standard 653 concerning records, reports, and inspector qualifications (Sections 4.8-4.10) are not incorporated by reference. API Standard 653, ''Tank Inspection, Repair, Alteration, and Reconstruction'' (3rd edition, December 2001, includes addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)). API-2510, “Design and Construction of LPG Installations” (8th edition, 2001). API Specification 12F, ''Specification for Shop Welded Tanks for Storage of Production Liquids'' (11th edition, November 1, 1994, reaffirmed 2000, errata, February 2007). API-12C, “Welded Oil Storage Tanks”, 15th edition, (forerunner to API 650). API Standard 650, ''Welded Steel Tanks for Oil Storage'' (11th edition, June 2007, addendum 1, November 2008)

	API Standard 620, ''Design and Construction of Large, Welded, Low-Pressure Storage Tanks'' (11th edition, February 2008, addendum 1 March 2009) API Standard 510, ''Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration'' (9th edition, June 2006). February 4, 2000, letter Agreement between OPS and EPA for jurisdictional boundaries.
Guidance Information	1. §195.432 general guidance: a. From §195.2 a breakout tank means a tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline. b. Per §195.1(c), §195.432(b) & (c) do not apply to anhydrous ammonia breakout tanks. c. Operator's written O&M procedures must cover the requirements of §195.432 and the applicable API Standard (ref. §195.402(a)). d. Engineering judgment (if allowed or called for by various Part 195 reference(s), such as API Standard 653) must be documented for each circumstance. e. All deficiencies documented by the operator's various inspection reports must either be remediated or there must be documentation as to why remediation is not required. 2. §195.432(a) guidance: a. §195.432(a) requires annual maintenance inspection of in-service breakout tanks that are not subject to the other inspection requirements in §195.432(b) and §195.432(c), such as anhydrous ammonia tanks and non-steel tanks. 3. §195.432(b) guidance: a. API 653 section 6.3.1 requires monthly (routine) visual inspection procedures for the following: b. Tank exterior surface checking for: i. Leaks, ii. Shell distortions, iii. Signs of settlement, iv. Corrosion, v. The condition of the: Foundation, Paint coating, Insulation systems, and Appurtenances, c. This list is not comprehensive, and exceptions and/or alternative requirements may apply d. API 653 section 6.3.2 requires a visual in-service external inspection by an API Std 653 Authorized Inspector. The interval shall be the lesser of: i. At least every 5 years or ii. At a time period equal to one quarter the measured shell thickness less the required shell thickness (RCA) divided by the corrosion rate in mils per year (N). iii. Insulation only needs to be removed to the extent necessary to determine the condition of the tank walls or roof. e. API 653 section 6.3.3 allows the use of an ultrasonic thickness inspection for determining a rate of uniform general corrosion while the tank is in service. When used the interval shall be the lesser of: i. If corrosion rate is unknown, at least every 5 years or

ii. If the corrosion rate is known, a time period equal to one half the measured shell thickness less the required shell thickness (RCA) divided by the corrosion rate in mils per year (N).

f. API 653 section 6.4 requires an out-of-service internal inspection, by an API Std 653 Authorized Inspector. The interval shall be the lesser of:
   i. If the corrosion rate is known based on actual measurements or similar service condition, the interval shall be set to insure the bottom plate minimum thickness at the next inspection is not less than the values listed in table 6.1 of API 653. The interval shall not exceed 20 years.
   ii. If corrosion rate is NOT known and similar service condition not available, the interval shall be within 10 years starting from a date when the tank became regulated, but no later than May 3, 2009, to establish a corrosion rate.
   iii. As applicable to tanks covered under §195.432(b), some tank bottoms cannot be inspected under API Standard 653 because the steel bottom has been repaired by a concrete cover. In this case, and possibly others, §195.432(b) allows an operator to use an assessment technique included in its operations and maintenance manual for the tank bottom.

g. API 653 6.8 requires the operator to maintain three forms of records:
   i. Construction Records
   ii. Inspection History, and
   iii. Repair/alteration history.

4. §195.432(c) guidance:
   a. Tanks built in accordance with API 2510 are those tanks used for liquefied petroleum gas (LPG or LP-gas).
      i. API 2510 defines LPG or LP gas as any material in liquid form that is composed predominantly of any of the following hydrocarbons or of a mixture thereof: propane, propylene, butanes (normal butane or isobutane), and butylene.
      ii. API 510 defines an "on-stream inspection" as an inspection used to establish the suitability of a pressure vessel for continued operation. Nondestructive examination (NDE) procedures are used to establish the suitability of the vessel, and the vessel may or may not be in operation while the inspection is being carried out. Because a vessel may be in operation while an on-stream inspection is being carried out, an on-stream inspection means essentially that the vessel is not entered for internal inspection.
      iii. API 510 section 6.3 requires each above ground LPG tank shall be given a visual external inspection, preferably while in operation, at least every 5 years or at the same interval as the required internal or on-stream inspection, whichever is less. The inspection shall, at the least, determine the condition of the exterior insulation, the condition of the supports, the allowance for expansion, and the general alignment of the vessel on its supports. Any signs of leakage should be investigated so that the sources can be established.
      iv. API 510 section 6.4 requires the period between internal or on-stream inspections shall not exceed one half the estimated remaining life of the vessel based on corrosion rate or 10 years, whichever is less. In cases where the remaining safe operating life is estimated to be less than 4 years, the inspection interval may be the full remaining safe operating life up to a maximum of 2 years.

	v. API 510 section 6.4 provides detailed information about corrosion rate determinations. 5. §195.432(d) guidance: a. The intervals of inspection referenced in paragraphs (b) and (c) began on the earliest of: i. May 3, 1999 ii. Last record date of the inspection (annual), or iii. Whenever API Std 653 program was established for the particular tank. 6. The operator must have written procedures. 7. If telltale/tell-tale (see API 650) holes are plugged ensure the operator has a process to remove the plugs and inspect. 8. Final Order Guidance: **a.** ***BP Pipeline (North America) Inc. [4-2007-5003] (July 19, 2010)*** – Found that even though the operator conducted the API Standard 653 required routine visual inspections of in-service breakout tanks, it failed to document and correct certain areas of non-compliance as prescribed by API Standard 653. The operator argued that it had completed the required inspections. The Final Order found that part of the routine inspection is the documentation of certain areas of non-compliance for follow-up action. CO/CP **b.** ***Kinder Morgan Energy Partners, L.P. [3-2007-5007] (November 16, 2010)*** Found that the operator had not performed required API Standard 653 inspections of its breakout tanks at the required intervals after the rule had been adopted. The operator argued these tanks were governed by §195.432(a) which requires tanks not governed by §195.432 (b) and (c) to be inspected once each calendar year not to exceed 15 months. The Final Order found that the tanks cited in the Final Order were governed by both §195.432 (b) atmospheric aboveground breakout tanks, and §195.432(c) above ground pressure breakout tanks built to API Standard 2510. Therefore, these tanks must be inspected at the intervals and accordance with their associated inspection standards, API Standard 653 for atmospheric tanks and API Standard 510 for pressure tanks. CO **c.** ***Sunoco Pipeline L.P. [4-2007-5040] (December 16, 2010)*** – Found that the operator failed to perform API 653 timely inspections of breakout tank inspections within the required intervals of §195.432 and API 653. Section 195.432(d) states that the interval for performing breakout tank inspections begins on May 3, 1999, or on the date of the last recorded inspection, whichever is earlier. The date that an operator acquires ownership of a breakout tank is not relevant for these purposes. Moreover, if the date of the last inspection cannot be determined based on the available records, an operator should perform an API 653 inspection immediately after acquiring a breakout tank from another operator. CO/CP
Examples of a Probable	1. The lack of a procedure is a violation of 195.402.

Violation or Inadequate Procedures	2. The lack of records is a violation of 195.404. 3. The operator did not follow written procedures. 4. Procedures with referenced edition(s) of API 653 or API 510 that are not the same editions as those incorporated by reference in whole or in part listed in §195.3. 5. Procedures that do not provide adequate guidance for the operator to meet the requirements of $195.432. 6. Records or lack of records showing that in-service anhydrous ammonia or non-steel breakout tanks have not been inspected once each calendar year not to exceed 15 months. 7. Records or lack of records showing that an operator's breakout tank(s) has not been inspected in accordance with the intervals or requirements of API Standard 653 section 6 or API 510 section 6. 8. For tanks where structural conditions prevent access to the tank bottom records or lack of records shows that the operator did not follow their procedures for assessing the integrity of such bottoms. 9. Records showing that Engineering judgment, if used, was not reasonable. 10. Tank condition showing either tank inspection recommended repairs have not occurred or that maintenance is not occurring. 11. Badly distorted tank shell. 12. Corrosion occurring in the critical area of the tank chime. 13. Repad telltale holes are plugged and the operator has no process to remove the plugs and inspect (API 653, Sec. 1.1.5 and API 650, Sec. 5.7.2.10). Repads edges are not rounded. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's procedures. 2. Engineering drawings/schematics. 3. Photos of tank nameplates. 4. Tank inspection records. 5. Photographs of observed tank condition issues. 6. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.434
Section Title	Signs
Existing Code Language	Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-78, 68 FR 53526, 09-11-2003
Interpretation Summaries	**Interpretation: PI-73-037 Date: 11-16-1973** Your inquiry was regarding §195.434, in which you asked for a definition of the words "around," "visible," and "visible to the public," as used therein. The term "around" means in the general vicinity, not necessarily on all prominent sides, of the pumping station, terminal, or tank farm located in places where they would be seen, and not easily missed, by the public. This, however, does not mean that signs are only required adjacent to public roads, lands, or waterways. They must also be located adjacent to privately owned property if a person approaching the facilities from that direction would not be able to see and read the other signs. "Visible" means that the sign must be readily discernable to the human eye at a reasonable distance. We cannot categorically determine if more than one sign would be required on a lengthy side or where hills or other obstructions are involved and, if so, on what spacing. The pipeline carrier must evaluate each particular situation and assure himself that the signs have been placed in such locations as will make at least one of the posted signs readily visible to a person approaching the plant facilities from that general direction.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	

Guidance Information	1. The operator must have written procedures. 2. Signs must be placed in the general vicinity, not necessarily on all prominent sides, of the pumping station, terminal, or tank farm and be located in places where they would be seen, and not easily missed, by the public. Signs must be legible. 3. Verify the accuracy of the operator's name on the sign. 4. Verify that the emergency phone number posted on the signs is correct. 5. Stickers applied to signs to update certain information are satisfactory, as long as they are permanently applied and remain legible. 6. Pipeline markers meeting the requirements of §195.410, may be used to satisfy this requirement, provided they are located within/on the facility fence or immediately adjacent to the fence.
Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did not follow written procedures. 4. The operator's procedures list the incorrect operator name and/or emergency contact information. 5. Operator's inspection records indicate a signing deficiency with no remediation. 6. Operator's pumping station or breakout tank area is not posted with signs as required. 7. The information on the operator's signs does not fulfill the requirements. 8. Contact information on the signs is incorrect, i.e. incorrect operator name, incorrect telephone number, or telephone number is no longer active. 9. Posted signs have become illegible as a result of fading, corrosion, or vandalism. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence Guidance	1. O&M procedures. 2. Photographs. 3. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	*O&M Part 195*
Revision Date	7 21 2017
Code Section	§195.436
Section Title	Security of Facilities
Existing Code Language	Each operator shall provide protection for each pumping station and breakout tank area and other exposed facility (such as scraper traps) from vandalism and unauthorized entry.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-22, 46 FR 38357, 07-27-1981.
Interpretation Summaries	**Interpretation: PI-10-0019 Date: 01-25-2011** Section §195.436 requires that each operator provide protection for each pumping station and breakout tank area and other exposed facility, including scraper traps, from vandalism and unauthorized entry. The existing configuration of manned 24 hours a day security cameras as described does not satisfy the requirement because no such protection is provided. Actions that could satisfy § 195.436 may include locking the pig piping scraper valve, constructing a fence adequate to protect the facility from vandalism and unauthorized entry, or both. **Interpretation: PI-80-012 Date: 08-13-1980** Your memorandum dated May 9, 1980, requested an interpretation concerning section 195.436. You gave a situation with a tank farm in a rural setting, with a hard surface road paralleling the front side of the tank farm, and with no surveillance or monitoring equipment installed to detect unauthorized entry. Questions: (1) Will either of the following fences meet the requirements of section 195.436? (a) A four strand, barbed wire fence surrounding the perimeter. (b) A four strand, barbed wire fence on three sides bounded by farm land with an eight-foot chain link fence on the front side of the tank farm. (2) Will hourly inspections of the tank farm facilities meet the requirements of §195.436? Interpretations: The intent of section 195.436 is to provide security from vandalism and entry by unauthorized persons. Although fencing is not necessarily required, one of the ways to comply with this regulation would be to construct a fence adequate to protect the facility from vandalism and unauthorized entry. A barbed wire fence is generally used to control livestock, but would not deter entry by unauthorized persons. Hence, neither of the fencing options you listed would meet the requirements of the regulation. Likewise, hourly inspections will not deter unauthorized entry or prevent vandalism and, therefore, will not meet the requirements of § 195.436.

	Interpretation: PI-76-0118 Date: 10-04-1976 This agency prescribes and enforces safety regulations applicable to the design, construction, operation, and maintenance of petroleum pipelines in interstate or foreign commerce. These regulations, which are contained in 49 CFR Part 195, do not govern right-of-way disputes. Carriers are required, however, to provide security for their facilities (§195.436) and to take appropriate remedial action, including shutting down the affected part of a system, in the event of an adverse or hazardous situation §195.402(c)). The threat of outside interference would not relieve a carrier's responsibility for compliance with these and other applicable requirements in Part 195.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-95-02, Increased Pipeline Transportation Security Measures** The Office of Pipeline Safety is advising pipeline owners and operators of the need to review their security procedures and plans as a result of a determination by the Secretary of Transportation that enhanced security awareness is appropriate at this time. While there is no information at this time to suggest that pipelines or other modes of transportation are specifically threatened, it is reasonable and prudent to ensure that measures are in place to prevent or deter possible criminal or terrorist acts against the U.S. transportation system. Pipeline operators should consider reviewing their security procedures with their employees to ensure that they are familiar with their responsibilities and that any suspect activity on or around pipeline facilities is appropriately reported. Additionally, pipeline operators should consider taking measures to improve the physical and operational security of their pipelines.
Other Reference Material & Source	TSA Pipeline Security Guidelines, December 2010 (This report is available on the WINDOT Library.)
Guidance Information	1. The operator must have written procedures. 2. The sides of an enclosure, constructed solely of barbed wire, are not considered adequate to prevent unauthorized entry. 3. The level of security for the facility may need to be enhanced, based on the threat posed by the surrounding area, i.e. an area that has a history of vandalism and/or sabotage. 4. Hourly inspections in and of themselves are not considered adequate security. 5. Entrance to the facility and appropriate structures in the facility should be locked. – Simply having a lock is insufficient. Locks must be securely fastened. 6. Simply locking items, such as valves or catchers, at a facility does not address the “shall provide protection from unauthorized entry” portion of the code. 7. By example, if a facility has a secure fence with a locked gate (meeting this requirement), the enclosed pig launcher is not required to be locked. 8. Remoteness of a facility alone or with a barbed wire enclosure and remote monitoring is not considered to be adequate protection to prevent vandalism or unauthorized entry.

	9. Isolated remote valves, are not considered other exposed facilities in relationship to this requirement; thereby not requiring perimeter security. 10. Fence should be properly maintained. No large gaps should exist that allows entry to the secure area. For example: gaps under fences, holes in fences and gates, etc. 11. The industry standard for a secure fence is a minimum of 6-foot-high chain link fence with 3 strands of barbed wire on top. The operator needs to evaluate the specific security requirements depending on the threats present in that area. 12. Final Order Guidance: **a.** ***Belle Fourche Pipeline [5-2009-5042] (November 21, 2011)*** - BFPL had no security fencing installed around the Donkey Creek Pump Station. Also, a 4.5 to 5 foot high security fencing around the Sussex Pump Station and Sussex Breakout Tank was only made of 4 foot high, 6-inch grid woven steel wire with 2 strands of barbed wire above it. This type of fence will keep livestock out of the facility but it is not adequate to prevent vandalism and unauthorized entry to the facility. BFPL argued that fencing was not needed because of the remote location and the presence of personnel at the Donkey creek facility and that Sussex had a fence. The type of security fencing at Sussex was determined to be inadequate and that the Donkey Creek security was inadequate regardless of the remoteness of the location and presence of station personnel who had other responsibilities besides security. The Final order found that Respondent failed to provide adequate protection from vandalism and unauthorized entry. CO **b.** ***Rocky Mountain Pipeline System, LLC [5-2006-5031] (June 18, 2009)*** – Found that the operator had not installed security fencing at 2 remote pump stations and 1 remote breakout tank area. The operator argued that because these stations were in remote areas, were electronically monitored from a remote location, and were regularly visited by operator personnel, 4 strand barbed wire fencing provided adequate protection from vandalism and unauthorized entry. Final Order stated that such fencing, even in combination with the other security measures, was insufficient security to deter unauthorized entry. CO **c.** ***Jayhawk Pipeline LLC [3-2002-5021] (December 11, 2003)*** – Found that the operator had not provided adequate security protection for some of its breakout tank areas because the operator only provided an 8-foot, chain-link fence around the breakout tank ladders and locked the breakout tank valves. The operator argued that this was adequate security, given the rural nature of the sites. The Final Order found that the operator must provide protection for the entire breakout tank area. CO
Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did follow written procedures. 4. Records that have no follow-up remediation of an operator's inspection that indicates a deficiency at a pump station or breakout tank facility's protection against vandalism or unauthorized entry provisions.

	5. Records indicating a systemic vandalism problem at a pump station or breakout tank when the operator has not taken additional preventative actions to prevent such vandalism. 6. The operator is not in compliance with the requirements in their O&M Manual. 7. The protection provided at a pump station or breakout tank does not prevent unauthorized entry or vandalism. 8. Protection against vandalism or unauthorized entry at pump stations and breakout tanks is in a condition that prevents it from being effective. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. O&M procedures. 2. Photographs. 3. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.438
Section Title	Smoking or Open Flame
Existing Code Language	Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.
Origin of Code	Original Code Document, 34 FR 15473, 10-04-1969
Last Amendment	Amdt. 195-22, 46 FR 38357, 07-27-1981.
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The operator must have written procedures. 2. An operator's procedures should describe how they identify and mark areas where accumulating flammable vapors or liquids present a hazard and how they prevent smoking and open flames within those areas. 3. No smoking and no open flame signs must be posted in accordance with their smoking and open flame procedures. 4. Operator personnel and contractors (as well as PHMSA inspectors) must observe the operator's smoking and open flames policy and posted signs. 5. An operator should take precautions to minimize the potential of accumulating flammable vapors or liquids when they are a hazard. 6. Final Order Guidance: **a.** ***Nustar Logistics L. P. [4-2005-5048] (March 11, 2009)*** – Found that the operator had failed to post No-Smoking signs at entrances to its pump station

	facilities. Operator argued that they had followed their O&M no smoking and open flame procedures and that § 195.438 was followed. The Final Order stated that an operator's procedures alone did not provide warnings to visitors who may not be privy to the operator's procedures upon entering the facilities, and No Smoking signs must be installed. CO
Examples of a Probable Violation or Inadequate Procedures	1. The lack of procedures is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did not follow written procedures. 4. An operator's procedures do not prevent smoking within areas of accumulating flammable vapors or liquids. 5. Operator's inspections or notes indicate a deficiency with its Smoking and Open Flame policy or its implementation but there have been no follow-up actions. 6. "No Smoking/No Open Flame" signs are not posted in accordance with the operator's procedures. 7. Personnel are not observing no smoking and no open flame policies of the operator. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's procedures. 2. Photographs. 3. Lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.442
Section Title	Damage Prevention Program
Existing Code Language	(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of above-ground structures by either explosive or mechanical means, and other earthmoving operations. (b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of the responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) or this section. (1) The state has adopted a one-call damage prevention program under Sec. 198.37 of this chapter; or (2) The one-call system: (i) Is operated in accordance with Sec. 198.39 of this chapter; (ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and (iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline. (c) The damage prevention program required by paragraph (a) of this section must, at a minimum: (1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located. (2) Provides for notification of the public in the vicinity of the pipeline and actual notification of persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program: (i) The program's existence and purpose; and (ii) How to learn the location of underground pipelines before excavation activities are begun. (3) Provide a means of receiving and recording notification of planned excavation activities. (4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

	(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins. (6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities: (i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and (ii) In the case of blasting, any inspection must include leakage surveys. (d) A damage prevention program under this section is not required for the following pipelines: (1) Pipelines located offshore. (2) Pipelines to which access is physically controlled by the operator.
Origin of Code	Original Code Document, 60 FR 14646, 03-20-1995
Last Amendment	Amdt. 195-60, 62 FR 61695, 11-13-1997.
Interpretation Summaries	**Advisory Bulletin ADB-2012-08, Inspection and Protection of Pipeline Facilities after Railway Accidents.** Buried pipelines are susceptible to damage even when depth- of-cover protection exceeds minimum Federal requirements. Pipeline owners and operators should inspect their facilities following a railroad accident or other significant event occurring in right-of-ways to ensure pipeline integrity. Also, during response operations, pipeline owners and operators need to inform rail operators and emergency response officials of the presence, depth and location of the pipelines so that the movement of heavy equipment on the right-of-way does not damage or rupture the pipeline or otherwise pose a hazard to people working in, and around, the accident location. Pipeline owners and operators, as a part of their public awareness program, need to inform rail operators and emergency response officials of the benefits of using the 811 “Call Before You Dig” program to identify and notify underground utilities that an incident has occurred in the vicinity of their buried facilities.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-06-03, Notice to Operators of Natural Gas and Hazardous Liquid Pipelines to Accurately Locate and mark underground Pipelines Before Construction-Related Activities Commence Near the Pipelines.** This advisory reminds and reinforces the importance of safe locating excavation practices near underground pipelines. PHMSA's pipeline safety regulations require pipeline operators to implement damage prevention programs to protect underground pipelines during construction related excavation. In addition, PHMSA recommends pipeline operators excavating in areas populated with other pipelines and utilities follow all consensus best practices and guidelines developed by the Common Ground Alliance. Recent serious incidents especially reinforce the importance of accurately locating and marking pipelines and highlight an urgent need for pipeline operators to review how they implement their damage prevention programs to prevent further accidents caused by construction related damage. This Advisory Bulletin provides guidance on how to do this.

Advisory Bulletin ADB-06-01, Notice to Operators of Natural Gas and Hazardous Liquid Pipelines to Integrate Operator Qualification Regulations into Excavation Activities.

PHMSA is issuing this advisory bulletin to pipeline operators to reinforce the need for safe excavation practices and recommend that pipeline operators integrate the Operator Qualification regulations into their marking, trenching, and backfilling operations to prevent excavation damage mishaps.

Advisory Bulletin Add ADB 04-03, Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities.

RSPA/OPS is issuing this advisory bulletin to owners and operators of gas and hazardous liquid pipeline systems on the potential for unauthorized excavations and the unauthorized installation of acoustic monitoring devices or other data acquisition devices on pipeline facilities. These devices are used by entities that hope to obtain market data on hazardous liquid and gas movement within the pipelines. Recent events have disclosed that devices were physically installed on pipelines without the owner's permission. Operators must control construction on pipeline right-of-ways and ensure that they are carefully monitored to keep pipelines safe. This is in line with our efforts to prevent third-party damage as reflected by our support of the Common Ground Alliance, which is a nonprofit organization dedicated to shared responsibility in damage prevention and promotion of the damage prevention Best Practices. This advisory bulletin emphasizes the need to ensure that only authorized and supervised excavations are undertaken along the nation's pipeline systems.

Advisory Bulletin ADB-02-01, Notice to Operators of Natural Gas and Hazardous Liquid Pipelines to Encourage Continued Implementation of Safe Excavation Practices.

RSPA is issuing this advisory notice to operators of natural gas and hazardous liquid pipelines to remind them of the importance of safe excavation practices. We have also asked our partners in the Common Ground Alliance, a new national non-profit damage prevention organization, and the Associated General Contractors of America and the National Utility Contractors Association, to help distribute this advisory.

Several recent incidents have provided the impetus to remind the pipeline operators of the importance of safe excavation practices. Increase in construction activity coincides with the arrival of spring in many parts of the country and extends through the summer months. Construction activity requires excavators to work around buried pipelines and other underground facilities, such as water, sewer, electrical and phone lines. Many private citizens also undertake excavation projects in the spring and summer months such as gardening, installing mailboxes, outdoor lights and other projects that require digging. Figures for excavation damage from RSPA's Office of Pipeline Safety (OPS) show an upward trend in the warmer months.

	Advisory Bulletin ADB-99-04, Directional Drilling and Other Trenchless Technology Operations Conducted In Proximity to Underground Pipeline Facilities. RSPA is issuing this advisory bulletin to owners and operators of natural gas and hazardous liquid pipeline systems to advise them to review, and amend if necessary, their written damage prevention program to minimize the risks associated with directional drilling and other trenchless technology operations near buried pipelines. This action follows several pipeline incidents involving trenchless technology operations which resulted in loss of life, injuries, and significant property damage. It also corresponds to National Transportation Safety Board (NTSB) Safety Recommendation P-99-1, which suggests that RSPA ensure that the operators' damage prevention programs include actions to protect their facilities when directional drilling operations are conducted in proximity to those facilities.
Other Reference Material & Source	CGA (Common Ground Alliance) for underground damage prevention best practices. State one call requirements for responding to one-calls, and marking requirements.
Guidance Information	1. An operator must have a written program to prevent damage to their pipeline by excavation activities. This may be a separate written program or made part of the operator's written O&M plan as required by §195.402(a). The written procedures should state the purpose and objectives of the damage prevention program, and provide methods and procedures to achieve them. Applicable state and local requirements should also be noted. [§195.442(a)]. 2. If there is more than one qualified One-Call center for an area the operator need only subscribe to one if 1) there is a central phone number for excavation activities **or** 2) if the various one-call centers communicate excavation notifications to one another. [195.442(b)] 3. A damage prevention program must include a listing of persons who normally engage in excavation activities (excavators) in proximity to the operator's pipeline. [195.442(c)(1)] 4. A damage prevention program must have a process for notification of the public in the vicinity of the pipeline. [195.442(c)(2)] 5. A one-call system or an information service provider may not be able to perform all the tasks required by the damage prevention program. However, an operator may still use these resources to assist in the compliance of this requirement. [195.442(c)(3)] 6. The process used to receive and record notifications of planned excavation activities must assure that all notifications are received and recorded. [195.442(c)(3)] 7. The process to assure notifications are addressed within the state mandated time requirements. 8. It is acceptable to use third parties to conduct meetings with excavators on behalf of the operator; however, the operator is ultimately responsible for ensuring notification of excavators as often as needed to make them aware of the operator's damage prevention program requirements. [195.442(c)(2)]

	9. Documentation of contractor meetings must be kept concerning a good faith attempt to include who was invited, who attended, and topics discussed. [195.442(c)(2)] 10. The operator is ultimately responsible to assure that all of the damage prevention requirements are being performed. [195.442(c)] 11. Notification of all excavators who normally operate within the vicinity of the operator's pipeline may be difficult therefore it is important that the operator's process assures that a reasonable effort has been made to identify all excavators. [195.442(c)(1)] 12. An operator's damage prevention program must have provisions for monitoring excavation activities that are in close proximity to their pipeline and for which the operator believes have a potential for damaging the operator's pipeline. [195.442(c)(6)(i)] 13. An operator's damage prevention program must have provisions for monitoring blasting activities that are in close proximity to their pipeline and for which the operator believes have a potential for damaging the operator's pipeline. This process must include leakage surveys. [195.442(c)(6)(ii)] 14. An operator's damage prevention program should have provisions for analyzing pipeline crossings or other abnormal loading situations. 15. Records must verify that the operator is following its damage prevention program. [195.404(c)(3) and 195.442(c)] 16. An operator's one-call records should indicate what potential excavation activities were in proximity to their buried pipeline and what actions the operator took to notify the excavator, and if applicable, actions they took to mark their pipeline. [195.442(c)(3), (4), and (5)] 17. An operator adheres to the damage prevention policy by placing one calls for excavations on the ROW and company owned facilities.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not have, or did not follow, a written program. 2. An operator does not participate in a qualified one-call system (see §195.442(b)(1) or (2), for receiving and recording notification of planned excavation activities. §195.402(b) 3. An operator's damage prevention program that lacks any of the following: a. A record of persons who normally engage in excavation activities (excavators) in proximity to the operator's pipeline. b. A process for notification of the public in the vicinity of the pipeline to make them aware of the operator's damage prevention program. c. A process for notifying excavators as often as needed to make them aware of the operator's damage prevention program. d. A process for receiving and recording notification of planned excavation activities. e. The process used to receive and record notification of planned excavation activities does not have a means to recover from equipment outages, so that no messages are lost. f. Procedures for monitoring excavation activities that are in close proximity to an operator's pipeline and for which the operator believes have a potential for damaging the operator's pipeline. g. Procedures for monitoring blasting activities that are in close proximity to an operator's pipeline and for which the operator believes have a potential for damaging the operator's pipeline.

	h. Excavator lists that have not been kept up to date and/or do not include excavators listed in the current local yellow pages directory, or other excavator listings, who are indicated as working in the area of the pipeline. i. An operator has not put forth a reasonable effort to assure actual notification of the identified excavators was carried out. Records that may demonstrate this are mailing lists and mailing frequency, or other documentation (meeting attendance records, etc.). j. An operator's public notification process (mailings, news media, and meetings) either has not been implemented or documentation fails to provide sufficient information about the existence and purpose of the operator's damage prevention program to the public (right-of-way residents or landowners). k. An operator who has not contacted an excavator who gave notice of their intent to excavate in the area of the pipeline. l. Operator does not maintain one-call records for their own excavations. m. Operators do not respond to one calls according to state mandated time frames. n. Operators do not retain records for two years (195.404(c)(3). o. An operator who has not provided temporary marking of their buried pipelines in the area of excavation activity before, as far as practical, the activity begins. p. The operator did not inspect their pipelines in which the operator has reason to believe could have been damaged by excavation activities. q. Unqualified personnel marking the pipelines. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Statements from contractors, public, or other persons. 2. Records supporting non-compliance. 3. Omission of records to support compliance. 4. Photographs of improper marking, lack of required marking, excavation damage, etc. 5. Copy of Damage Prevention Program written plan or specific procedure. 6. Copy of brochure, letters, news media advertisements indicating communications failed to provide required information to the public. 7. By admission, records, or lack of records that the operator has not identified (on a current basis) persons who normally engage in excavation activities in the area in which the pipeline is located. 8. Documentation of meetings, invitation lists, and list of those that attended the meeting. 9. Lack of a program document.
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	7 21 2017
Code Section	§195.444
Section Title	CPM Leak Detection
Existing Code Language	Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) must comply with API RP 1130 (incorporated by reference, see § 195.3)in operating, maintaining, testing, record keeping, and dispatcher training of the system.
Origin of Code	Original Code Document, 63 FR 36373, 07-06-1998
Last Amendment	Amdt. 195-99, 80 FR 188, 01-05-2015.
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-10-01, Leak Detection on Hazardous Liquid Pipelines.** The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this Advisory Bulletin to advise and remind hazardous liquid pipeline operators of the importance of prompt and effective leak detection capability in protecting public safety and the environment. The Pipeline and Hazardous Materials Safety Administration (PHMSA) is advising and reminding hazardous liquid pipeline operators of the importance of prompt and effective leak detection capability in protecting public safety and the environment. In order to ensure the safe and environmentally sound operation of their hazardous liquid pipelines, the operating plans and procedures required by the pipeline safety regulations should include the performance of an engineering analysis to determine if a computer-based leak detection system is necessary to improve leak detection performance and line balance processes. If an operator that does not have a computer-based leak detection system performs an engineering analysis and determines that such a system would not improve leak detection performance and line balance processes, the operator should perform the periodic line balance calculation process outlined herein and take any other necessary actions required to ensure public safety and protect the environment.
Other Reference Material & Source	API Recommended Practice 1130, ‘‘Computational Pipeline Monitoring for Liquids: Pipeline Segment’’ (3rd edition, September 2007). (API RP 1130), IBR approved for §§ 195.134 and 195.444 API-1149, “Pipeline Variable Uncertainties and Their Effect on Leak Detectability”, November, 1993. API-1155, “Evaluation Methodology for Software-based Leak Detection Systems”, 1st edition, February, 1995 (replaced by API 1130).

Guidance Information	1. From §195.2 Computation Pipeline Monitoring (CPM) means a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release. 2. Though this rule does not require an operator to install a CPM if the operator does not already have one the operator's leak detection evaluation required under §195.452(i)(3) may indicate that one is needed. 3. Simple line balance or flow-rate alarms are not necessarily CPM systems. 4. SCADA systems are not CPM systems 5. SCADA may be used to gather or derive CPM source data 6. A CPM system may be an ancillary feature of a sophisticated SCADA system, or a completely independent system. 7. Implementation of a CPM system may impact SCADA design and configuration parameters. 8. If the output of a computer-based CPM-type system provides some information or alarm, such that company procedures require the Controller to take immediate action to change the hydraulic state of the pipeline, then that CPM will be inspected against §195.134 and §195.444. 9. If the output of a computer-based CPM-type system is connected to any field stations (perhaps through a SCADA system) to automatically change the hydraulic state of the pipeline, then that CPM will be inspected against §195.134 and §195.444. 10. If the output of a computer-based CPM-type system provides some information or alarm, such that company procedures require the Controller to undertake further analysis or some other more in-depth review before hydraulic action is undertaken, then that CPM will not be inspected against §195.134 and §195.444.
Examples of a Probable Violation or Inadequate Procedures	1. The lack of a procedure is a violation of 195.402. 2. The lack of records is a violation of 195.404. 3. The operator did not follow written procedures for instrumentation testing and maintenance. 4. The operator did not follow written procedures for CPM testing. 5. Operation procedures that have no script, checklist, or guide to assist operations personnel in the event of an alarm. 6. Either no initial CPM system testing to verify the system operation or records for such testing have not been maintained in accordance with the operator's procedures and 195.404(c)(3). 7. Large variation between actual events and CPM generated information, without some form of prompt, post-event analysis and possible remediation. 8. Through interviews and/or observation pipeline personnel responsible for operation and maintenance of the system appear to be inadequately trained. Record observations in the violation report. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Procedures. 2. Test and maintenance records. 3. Instrument manufacturer’s recommended maintenance practices. 4. Alarm records. 5. Abnormal operations reports. 6. Post-accident analysis reports. 7. Discharge pressure records. 8. Unscheduled shutdown or flow diversion reports. 9. Lack of procedures or records.
Other Special Notations	