Operations & Maintenance Enforcement Guidance

Part 195 Subpart F

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Part 195 Subpart F

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 to the implementation scenarios presented in the materials. Alternative approaches are not precluded if they satisfy the requirements of the applicable regulation(s).

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

Term	Definition	Definition Source
Abandoned	Permanently removed from service	192.3 195.2
Abandoned pipeline	A pipeline permanently removed from service that has been physically separated from its source of gas or hazardous liquid and is no longer maintained under regulation 49 CFR Parts 192 or 195, as applicable. Abandoned pipelines are usually purged of the gas or liquid and refilled with nitrogen, water, or a non-flammable slurry mixture.	GPTC
Abnormal operating condition	A condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may: (a) Indicate a condition exceeding design limits; or (b) Results in a hazard(s) to persons, property, or the environment	192.803 195.503
Abnormal operation	Exceeding operating design limits, including (i) unintended closure of valves or shutdowns; (ii) increase or decrease of flow rate outside of normal operating limits; (iii) loss of communications; (iv) operation of any safety device; and (v) any other foreseeable malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property.	192.605(c) 195.402(d)
Accessible to public	An area is accessible to the public if entrance into the area is not physically controlled by the operator and may be entered without difficulty (i.e. - does not have any man-made or natural impediments to prevent public access).	interpretation PI-91-022
Accident	A release of the hazardous liquid or carbon dioxide transported that results in any of the following: (a) explosion or fire not intentionally set by the operator. (b) release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is: (1) not otherwise reportable under this section; (2)not one described in Sec 195.52(a)(4); (3) confined to company property or pipeline right-of-way; and (4)cleaned up promptly (c) Death of any person; (d) personal injury necessitating hospitalization; (e) estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.	195.5
Active corrosion	Continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety or the environment.	192.3 195.553

Term	Definition	Definition Source
Actual wall thickness	The measured wall thickness of pipe from its inner surface to its outer surface. For new pipe, this measured dimension must be within tolerances stated in the manufacturer's specifications. Actual wall thickness of installed pipe can be determined by using an ultrasonic thickness gauge (UT gauge).	
Administrator	The Administrator, Pipeline Hazardous Materials Safety Administration or his or her delegate.	192.3 195.2
Aerial crossing	Where a pipeline crosses over a river, deep gully, or other geographic feature, and is not buried or submerged in water but is exposed to atmosphere. The pipeline may be suspended by cables, attached to the girders of a bridge, or for short crossings, engineered to support itself.	
Alarm	An audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.	192.3 195.2
Alternating current (AC)	An electrical current whose direction or polarity changes with time. The polarity or cycles are due to the alternating magnetic fields used in its generation. The time frequency cycle is also referred to as hertz. In North America, the common frequency is 60 hertz (cycles per second).	
Alternating current voltage gradient (ACVG)	A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.	ANSI/NACE SP0502
Ambient temperature	The temperature of the surrounding air or environment. This thermal condition is often referenced to calculate how it might affect the design or operation of various devices on the pipeline.	
Amphoteric metal	A metal that is susceptible to corrosion in both acidic and alkaline environments.	NACE/ASTM G193 Corrosion Terms
Anhydrous ammonia	NH_3 is a toxic colorless gas with a pungent-suffocating odor under atmospheric conditions. It is normally shipped in a compressed liquid state and is considered to be a hazardous liquid. It will burn skin if touched and can be deadly if inhaled.	
Anode	The electrode in a corrosion cell where oxidation or corrosion occurs. In a pipeline-related CP system, the anode is designed as the sacrificial material installed to purposely corrode and protect the structure (pipeline, tank bottom, or other underground structure). There are two basic types of anodes: the galvanic and the impressed current types.	
Anode (ground) bed	One or more anodes installed below the earth's surface for the purpose of supplying cathodic protection.	NACE SP0169
Anomaly	Any kind of imperfection, defect, irregularity, or deviation from the normal that may be present in either measurements or the physical facility.	
Appurtenance	Any part of a pipeline that may be subjected to pump or compressor discharge pressure including, but not limited to, pipe, valves, fittings, flanges, and closures.	

Term	Definition	Definition Source
Assessment	The use of testing techniques as allowed in this subpart (O) to ascertain the condition of a covered pipeline segment.	192.903
Backfilling	The technique for covering a newly constructed or recently unearthed pipeline so that adequate fill material is provided and compacted around the pipe to completely fill the excavation. The fill material must be suitable and free of rocks and other debris to prevent damage to the coating and the pipe. Rock shield, concrete and other coating methods may help protect the pipe during backfilling. Proper backfilling is critical so that the pipe is properly supported and not subjected to added stresses due to soil subsidence or movement.	
Ball valve	A valve in which a solid metal sphere with a hole in the center rotates within the valve body to control the flow of fluids. The ball usually rotates within a set of sealing rings.	
Barlow's formula	$P = 2St/D$ The mathematical formula that calculates the relationship of internal pressure to allowable stress, nominal thickness, and diameter of the pipe. Simply stated, Barlow's Formula calculates the pressure containing capabilities of pipe. The formula takes into account the pipe diameter (D), wall thickness (t), and the manufacturer's specified minimum yield strength of the pipe (S).	
Barrel	A unit of liquid petroleum measurement equal to 42 U.S. standard gallons.	195.2
Basic sediment and water (BS&W)	A test made on fuel oil or crude oil to show the approximate amount of sediment and water contained in the sample.	
Batch	A quantity of one type of product or material pumped within a pipeline. Often different types of crude oils or products, known as "batches," are pumped in front of or behind one another within the same pipeline. Depending on the physical characteristics of the crude or products, the batches may stay relatively separate or mix (commingle) as they travel within the pipeline. Batch sizes can vary between a few hundred barrels to hundreds of thousands of barrels.	
Batching	Batching is the process of pumping a certain quantity of crude oil or petroleum product next to one of a different type. As different batches arrive at their destinations, valves are opened and closed to divert the different products to the correct locations, such as tanks or even other customer pipelines.	
Bell hole	An enlarged hole other than a continuous trench, dug over and along the side of buried pipelines or in a trench to allow room for persons to perform maintenance-related work on the pipeline (i.e., coating repairs, welding, connections, or replacing pipe). In the broad sense, any larger hole, other than a ditch, opened for pipeline work. Smaller holes may be called key holes or pot holes.	
Berm	A raised mound of soil usually placed around structures to form a dam such as those used around tanks for containing possible spills or overflows.	

Term	**Definition**	**Definition Source**
Blister	A dome-shaped projection on the surface of a coating resulting from the local loss of adhesion and lifting of the film from an underlying coat or from the base substrate.	NACE/ASTM G193 Corrosion Terms
Boiling point	The temperature at which a liquid changes into a gas.	
Boilover	A condition that occurs during prolonged tank fires where heavier crude oils eventually heat up to a temperature of 400 to 500° F. The hot oil may circulate and come in contact with water in stratified layers or at the tank's bottom. When this occurs, the water quickly expands to steam at a 1,700 to 1 volume increase. This usually causes a violent explosion which blows the tank's contents upward causing a fireball and creating a wave of burning froth which can travel up to 20 miles per hour away from the tank.	
Bond	A connection, usually metallic, that provides electrical continuity between structures that can conduct electricity.	NACE SP0169
Breakout tank	A tank used to: (a) relieve pressure 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.	195.2
Brine	A strong solution of salt(s) with totally dissolved solid concentrations in the range from 40,000 to 300,000 or more ppm (parts per million or milligrams per liter).	
Buckle	A partial collapse of the pipe wall causing the pipe to flatten, become more oval or flatten due to excessive stresses associated with soil instability, landslides, washouts, frost heaves, earthquakes, etc. Buckles may be small, causing localized kinking or wall wrinkles, or global, involving several lengths of pipe that may buckle down, laterally, or vertically. Buckles cause localized stress concentrations and must not be installed in new construction. If found in existing systems, an analysis should be performed.	
Bulge	A localized expansion or swelling of pipeline components beyond their specified diameter. Bulging may be caused by over pressurization or exceeding the specified yield strength of the material.	
Buried	Covered or in contact with soil.	195.553
Caliper pig	A mechanical device used to measure the internal diameter of a pipeline.	
Cap pass	The final pass of the welding process.	
Carbon dioxide	CO_2 A fluid consisting of more than 90% carbon dioxide molecules compressed to a supercritical state.	195.2
Carbon steel	By common custom, steel is considered to be carbon steel when (1) no minimum content is specified or required for aluminum, boron, chromium, cobalt, columbium, molybdenum, nickel, titanium, tungsten, vanadium, zirconium, or any other element added to obtain a desired alloying effect; or (2) the specified minimum content does not exceed 1.62% for manganese or 0.60% for copper.	GPTC

Term	Definition	Definition Source
	All carbon steels may contain small quantities of unspecified residual elements unavoidably retained from raw materials. These elements (copper, nickel, molybdenum, chromium, etc.) are considered incidental and are not normally determined or reported.	
Casing	A pipe designed and installed to surround and protect a pipeline from external stresses and damage.	
Cathodic protection	A technique to control the corrosion of a metal surface by making the structure work as the cathode of an electrochemical cell. *(Typically, two types of CP systems are used: Galvanic systems use a series of sacrificial anodes of a more active metal (typically zinc or magnesium) to supply the current to the buried structure. Galvanic anodes continue to corrode, and need to be replaced periodically. Impressed current systems use anodes connected to a DC power source (rectifier - see definition). Anodes are installed as a ground bed or deep well to provide the current flow to the buried structure.)*	NACE SP0169
Centrifugal pump	A mechanical device used to boost the pressure of fluids in a pipeline system. Centrifugal pumps contain a rotating impeller or rotating vanes mounted on a shaft rotated by an external power source, usually an electric motor or a natural gas powered engine. The rotating impeller uses centrifugal force to move fluids in a steady stream (without pulsation).	
Centrifuge	A machine that uses centrifugal force to separate substances of varying densities, also called the shakeout or grindout machine. A centrifuge spins at high speeds, forcing the heavier substances to the bottom of a sample container. Centrifuges are commonly used to separate the water and sediment contained in crude oils.	
Centrifuge test	A test to determine the amount of basic sediment and water (BS&W) in samples of oil or emulsion.	
Check valve	A valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction	195.450
Cleaning pig	A mechanical device run inside a pipeline that uses cups, scrapers, or brushes to remove dirt, paraffin, rust, mill scale, or other foreign matter from the inside of a pipeline. Cleaning pigs are run to increase the operating efficiency of a pipeline or to prepare the pipeline for an internal inspection. May be used in conjunction with cleaning fluids.	
Close interval survey	A potential survey with pipe-to-soil readings generally taken a maximum of two and one half (2 1/2) to five (5) feet apart.	ANSI/NACE SP0502
Coalescence	The joining or fusing of metals produced by extreme temperatures achieved from an electrical arc between the metal electrode of a welding rod and the base metal of the pipe or other metallic structure. The welding machine produces the high electrical current and voltage necessary to get the arc to jump between the two metals.	
Coating	A liquid, liquefiable or mastic composition that, after application to a surface, is converted into a solid protective, decorative or functional adherent film.	

Term	Definition	Definition Source
Combustion	The process of burning where a flammable substance is subjected to a heat source in the presence of oxygen. The degree of heat and the ratio of air to fuel will depend on the flammability characteristics of the substance.	
Commercially navigable waterway	A waterway where a substantial likelihood of commercial navigation exists.	195.450
Commingle	The mixing of gases or liquid products in a pipeline. With liquids, commingled products between batches in a pipeline are also referred to as "interface."	
Component	A component is considered any part of a pipeline that may be subjected to pump including, but not limited to, pipe, valves, fittings, flanges and closures.	195.2
Composite pipe repair	A non-metallic reinforcement of pipe using a variety of composite repairs. The reinforcements may include fiberglass, carbon fibers, and epoxies to provide hoop reinforcement to corrosion and mechanical damage. Varieties of composite repairs include Clockspring®, Armor Plate®, and Diamond Wrap®.	
Computational pipeline monitoring (CPM)	A software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating abnormality that may indicate a commodity release or leak.	195.2
Conductivity	The ability of a substance (measured in ohm-cm) to conduct an electric charge or current due to the presence of positively or negatively charged ions.	
Control piping	Pipe, valves and fittings used to interconnect air, gas, or hydraulically operated control apparatus.	GPTC
Control room	An operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.	192.3 195.2
Control valve	A mechanical device used to vary flow rates and pressures on pipelines. Positioning signals are sent to the valve to achieve and maintain the desired set point. A control valve may be a globe, plug, or ball-type valve. Its actuator may be pneumatic, hydraulic or electrically driven.	
Controller	A qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operations functions of the pipeline facility.	192.3 195.2
Conversion of Service	A steel pipeline previously used in service not subject to this part	192.14 195.5
Corrosion	The deterioration of a material, usually a metal, that results from a reaction with its environment.	NACE SP0169
Corrosion rate	The rate at which corrosion proceeds.	NACE SP0169
Corrosive product	A corrosive material as defined by the DOT Hazmat Regulations (Title 49 CFR 173.136) means a liquid or solid that causes visible destruction of, or irreversible alterations in, living tissue by chemical action at the site of contact.	195.2, 29 CFR 1910.1200 App A

Term	Definition	Definition Source
Coupon	A small, carefully weighed and measured specimen of metal that is used to determine metal loss caused by corrosion over a specified period of time.	
Covered task	An activity, identified by the operator, that: (1) Is performed on a pipeline facility; (2) Is an operations or maintenance task; (3) Is performed as a requirement of this part; and (4) Affects the operation or integrity of the pipeline.	192.801 195.501
Cracks	Cracks in line pipe are separations in the molecular structure of the base metal and form as a result of improper manufacturing, construction, operational stresses, or mechanical damage. Cracks are detrimental to the pipe's pressure restraining capabilities and can propagate into complete failure or rupture zones.	
Criteria	Standards on which a judgment or decision is made. The standard is established by rule, test, standard, consensus, or other means.	
Critical Interference bond	An interference bond whose failure would jeopardize structural protection. 'Critical bonds' are metallic connections between adjacent buried structures that, if not connected, would allow detrimental corrosion to occur on one facility. The bond is only critical to the more negative pipeline facility, or the one losing current to the other facility.	
Crude oil	The raw substance found in the earth that is a varying mixture of all the hydrocarbon atoms.	
Current	The flow of electrons in a circuit, measured in amperes (amps).	
Deep anode (ground) bed	A ground bed in which the anodes are placed far below the earth's surface in a single vertical hole. Deep ground beds are typically considered 50 feet or deeper.	
Defect	An imperfection in a pressure vessel or pipe that, depending on the type of defect, should be analyzed using a recognized and approved procedure, such as ASME B31G or RSTRENG. Defects may need to be repaired or removed, or the operating pressure lowered, depending on operating requirements of the facility.	
Dent	Is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.	192.309(b)
Design formula - liquids	Based on Barlow's Equation, this formula is used to calculate the maximum design pressure of new pipe, and is determined in accordance with the following formula. When used to calculate liquid pipeline design pressure, additional factors of E (seam joint factor determined in accordance with §195.106(e) and F (standard design factor as found in §195.106(a)), which make the final liquid design formula P=(2ST/D) x E x F.	195.106
Destructive testing	A physical testing process (such as a burst or a tensile test) during which the specimen being tested is rendered unusable.	

Term	**Definition**	**Definition Source**
Determine	To establish or ascertain definitely after considering an investigation or calculation. This is critical in differentiating between "discovering" vs. "determining" with respect to required time frames with which to file a "safety-related condition" report to the Office of Pipeline Safety (191.25 and195.56(a)). However, for integrity Management (§§192.933 and 195.452) there is no distinction between discovery and determination.	195.56(a), 192.933, 195.452
Dike	The perimeter of an impounding space forming a barrier to prevent liquid from flowing in an unintended direction.	
Direct assessment (DA)	An integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.	192.903 195.553
Direct current (DC)	An electrical current whose polarity or direction is constant with respect to time. DC current is typically used in impressed current cathodic protection systems. A rectifier is used to produce DC current.	
Disbondment	The loss of adhesion between a coating and the substrate (pipe surface).	NACE/ASTM G193 Corrosion Terms
Discovery	To find, obtain knowledge or information, or become aware of a condition for the first time. For IM, discovery is when an operator has adequate information about the condition to determine a potential threat (FAQ-58).	
Distributed anode bed	A ground bed where the anodes are spread over a wide geographical area. Usually employed to protect densely routed buried piping systems, such as in compressor station yards.	
Double submerged arc weld (DSAW)	A pipe having longitudinal or spiral butt joints produced by at least two weld passes, including at least one each on the inside and outside of the pipe. Coalescence is produced by heating with an electric arc or arcs between the bare metal electrode or electrodes and the work. The welding molten metal is shielded by a blanket of granular, fusible material on the work that is used to reduce the impurities (slag) introduced from the surrounding air. Pressure is not used and filler metal for the inside and outside welds is obtained from the electrode(s).	GPTC
Downstream	The direction in which the fluid is going with regard to a reference point. With compressor and pump stations, downstream would be the discharge side of the facility.	
Elbow (ELL)	A pipe fitting that makes an angle in a pipe run. Unless stated otherwise, the angle is usually assumed to be 90°. In larger pipelines, fitting type elbows may not be recommended due to their abrupt change in direction. Piggable lines should be equipped with bends of a minimum bend ratio of 1 1/2D, but the actual radius depends on the type of pig.	

Term	Definition	Definition Source
Electric flash welded pipe	Pipe having a longitudinal butt joint wherein coalescence is produced simultaneously over the entire area of butting surfaces by the heat obtained from resistance to the flow of electric current between the two surfaces, and by the application of pressure after heating is substantially completed. Flashing and upsetting are accompanied by the expulsion of metal from the joint.	GPTC
Electric fusion welded pipe	Pipe having a longitudinal butt joint wherein coalescence is produced in the preformed tube by manual or automatic electric-arc welding. The weld may be single or double and may be made with or without the use of filler metal.	GPTC
Electric resistance welded (ERW) pipe	Pipe which has a longitudinal butt joint wherein coalescence is produced by the application of pressure and by the heat obtained from the resistance of the pipe to the flow of an electric current in a circuit of which the pipe is a part.	GPTC
Electrical isolation	The condition of being electrically separated from other metallic structures or the environment.	NACE SP0169
Electrical resistance probes	An electronic probe that can be used in systems where gas or liquids (including hydrocarbons) are present to determine metal loss over time by measuring the increase in the resistance of the electrode as its cross-sectional area is reduced by corrosion. The resistance of the electrode is then compared with the resistance of a reference electrode.	
Electrical survey	A series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipe.	192.3 195.553
Electrode	An electronic conductor used to establish electrical contact with an electrolyte as part of a cathodic protection circuit.	
Electrolyte	A chemical substance containing ions that migrate in an electric field. Electrolytes can play a role in external corrosion or internal corrosion of metallic pipelines. For external corrosion, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged piping system, including the moisture and other chemicals contained therein. For internal corrosion, electrolyte refers to the chemicals contained in water on the inside the pipeline, including solutions of salts, acids and bases.	GPTC
Electrolytically shorted/coupled casing	A casing with a low casing to pipe resistance due to the presence of an electrolyte in the casing/pipe annulus. Electrolytically shorted or coupled casings may be shorted periodically and not continuously. These casing are not considered to be metallically shorted.	
Emergency flow restricting device (EFRD)	A check valve or remote control valve.	195.450
Emergency response personnel	Any persons engaged in the response to an emergency, including firefighters, police, civil defense/emergency management officials, sheriffs, military, manufacturing and transportation personnel.	
Environment	The surroundings or conditions (physical, chemical, mechanical) in which a material exists.	NACE/ASTM G193 Corrosion Terms

Term	Definition	Definition Source
Erosion	Abrasive metal loss caused by high surface velocity of the transported media, particularly when entrained solids or particulates are present.	
Evaluation (OQ)	A process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following: (a) Written examination; (b) Oral examination; (c) Work performance history review; (d) Observation during (1) performance on the job, (2) on the job training, or (3) simulations; or (e) Other forms of assessment	192.803 195.503
Excavation activities	Excavation, blasting, boring, tunneling, backfilling, the removal of above ground structures by either explosive or mechanical means, and other earth moving operations.	192.614 195.442
Excavation damage	Any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection, or the housing for the line device or facility.	192.1001
Explosive	To undergo a rapid chemical reaction with the production of noise, heat, and violent expansion of gases, or to burst violently as a result of pressure.	Webster's
Exposed pipeline	Any part of a pipeline not completely buried, and partially exposed to the atmosphere.	
Exposed underwater pipeline	An underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.	192.3 195.2 195.413
External corrosion direct assessment (ECDA)	A four-step process that combines pre-assessment, indirect inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.	192.925 195.553
Fail-Safe	A design feature which will maintain or result in a safe condition in the event of malfunction or failure of a power supply, component, or control device. Fail-safe may occur by three methods: fail open, fail close, or fail at last position.	193.2007
Filler pass	The third and subsequent passes of welding with the purpose of filling the joint with metal. Filler passes follow the stringer and hot passes, and precede the cap weld.	
Fire surface area	The approximate surface area inside a round storage tank that is determined by using the formula diameter squared, times 0.8 (D^2 x 0.8). This equation is used to calculate the amount of fire suppressant foam needed to extinguish tank fires. It can also be used to estimate the amount of water or snow a tank roof might be supporting.	
Fitting	A part used in a piping system, for changing direction, branching or for change of pipe diameter, and which is mechanically joined to the system.	

Term	Definition	Definition Source
Fixture	Devices or components which transfer the load from the pipe or structural attachment to the supporting structure or equipment. They include hanging type fixtures such as hanger rods, spring hangers, sway braces, counterweights, turnbuckles, struts, chains, guides and anchors, and bearing type fixtures such as saddles, bases, rollers, brackets, and sliding supports.	
Flammable	A substance that will burn readily or quickly. OSHA defines flammable substances as those materials that have the ability to generate ignitable vapors (also referred to as the material's flash point) with temperatures at or below 100°F.	
Flammable (explosive) limit	The range of a gas or vapor concentration that will burn or explode if an ignition source is introduced. Limiting concentrations are commonly called the "lower explosive or flammable limit" (LEL/LFL) and the "upper explosive or flammable limit" (UEL/UFL). Below the explosive or flammable limit, the mixture of product in air is too lean to burn, and above the upper explosive or flammable limit, the mixture is too rich to burn.	
Flammable liquid	A liquid having a flash point of not more than 60.5º C (141º F) or any material in a liquid phase with a flash point at or above 37.8 ºC (100º F).	49 CFR 173.130
Flammable product	Mean "flammable liquid" as defined by §173.130 Class 3 - Definitions of this chapter.	195.2
Flaring	The venting and igniting of flammable vapors or gas from a pipeline.	
Floating roof	A storage tank covering that rests on the surface of a hydrocarbon liquid in the tank and rises and falls with the liquid level. The use of a floating roof eliminates the vapor space above the liquid which could allow for air to mix with the oil or refined product and create a fire hazard. The floating roof also conserves the lighter hydrocarbon atoms that might otherwise evaporate out of the liquid. Floating roofs can also be found on tanks with solid roofs for the same purposes. In these instances, the floating roof is referred to as an "internal floating roof."	
Flow line	A smaller pipe run within a gathering lease that connects a flowing well to a storage tank. These lines typically have little if any pressure in them as the liquids travel to the lease tank. These lines are considered not regulated by PHMSA since they are part of the gathering system.	
Fluid	A substance (as a liquid or gas) capable of flowing or conforming to the outline of its container, that easily yields to pressure.	
Foreign structure	Any metallic structure that is not intended as a part of a system under CP.	
Frictional loss	The loss of fluid pressure (head) experienced when fluid flows through a pipeline. The amount of friction loss depends upon viscosity of the fluid, velocity of the fluid, roughness of the pipe's interior wall surface, size of the pipe, and the length of the pipeline.	

Term	Definition	Definition Source
Frothover	The continuous burping and frothing of a tank's contents over the side as a result of a tank fire. Frothover happens when the tank product contains water that comes into contact with hot oil.	
Furnace lap welded pipe	Pipe which has a longitudinal lap joint that is produced by the forge welding process. In this process, coalescence is produced by heating a preformed tube to welding temperature and then passing it over a mandrel. The mandrel is located between the two welding rolls that compress and weld the overlapping edges.	GPTC
Galvanic anode	A metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the electron source in one type of cathodic protection.	NACE SP0169
Galvanic corrosion	Accelerated corrosion of a metal because of an electrical contact with a more noble metal or non-metallic conductor in a corrosive electrolyte.	NACE/ASTM G193 Corrosion Terms
Galvanic series	A list of metals and alloys arranged according to their relative electrolytic potentials to one another in a given environment. The metals or alloys higher on the list (more negative) are anodic to those lower on the list, and the metals or alloys lower on the list (more positive) are cathodic to those higher on the list.	
Gate valve	A valve in which a thick slab of metal with a hole in the bottom half slides between two sealing elements. When the slab is in the upper position, the hole aligns with the valve body ports and allows flow.	
Gathering line (hazardous liquid)	A pipeline 219.1 mm (8 5/8 in) or less nominal outside diameter that transports petroleum from a production facility. *(Gathering lines have limited jurisdiction by the Office of Pipeline Safety. Additional information regarding jurisdiction can be found in §195.11.)*	195.2
Gauging	The process of conducting certain measurement-related tests to crude oil or other refined products in the field. When used in conjunction with storage tanks, it uses a specialized instrument to determine the liquid level of a tank.	
Gauging hatch	The small door opening in a tank lid or other vessel through which measuring and sampling are performed.	
Gauging pig (gauging plate)	A tool inserted into a pipeline to determine the largest internal diameter restriction. The plate only provides information on the largest restriction, but gives no information as to the number of restrictions, or their location along the pipeline.	
Gauging table	Volumetric tables prepared by engineers to calculate the number of barrels or cubic meters for any given depth of liquid in a tank. They are sometimes called strapping tables. Gauging or strapping tables are specific to only one tank and account for individual differences in internal components and other volume affecting factors.	
General corrosion	Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion.	192.485(a)
Geometry (geo) pig	Any of a variety of in line tools designed to measure the internal geometry and configuration of a pipeline, including dents, ovality and wrinkles, bend radius and angle and changes in wall thickness.	

Term	Definition	Definition Source
Geophone	A geophone is an acoustical monitoring device that is used to magnify sounds in and around pipelines. Geophones are typically used to monitor the passage of pipeline pigs or to detect leaks.	
Girth weld	A complete circumferential weld joining pipe end-to-end, also called a butt weld. An actual girth weld is usually made up of a number of weld passes beginning with the root pass or stringer bead and completed with the cap pass. Girth welds are made according to an operator's welding procedure.	
Globe valve	A valve internally equipped with a flat or conical plug attached to a stem that blocks flow when it is seated in a circular orifice. The body of valve is normally spherical in shape with a lateral incoming flow-path being directed vertically through the closure seat, then exiting again laterally. This radical change in flow-path causes the characteristic attribute of a comparatively large pressure drop across this type of valve. Throttling or total shut-off is obtained by adjusting the plug downward against the flow-path toward the mating seat. Globe valves are most typically used in a process plant environment.	
Ground temperature	The temperature of the earth at pipe depth.	
Gulf of Mexico and its Inlets	The waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.	192.3 195.2
Half-cell (electrode)	A device that contains a conductive electrode immersed in a surrounding conductive electrolyte, and used to measure the effectiveness of cathodic protection systems. A half cell may be made of a variety of materials, but typically is a copper-copper sulfate for soil readings, or a silver-silver chloride for readings taken in a saline environment.	
Hazard to navigation	A pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.	192.3 195.2
Hazardous liquid	Means petroleum, petroleum products, or anhydrous ammonia.	195.2
High consequence areas (HCAs) - hazardous liquids	Regions of the United States where the consequences of a hazardous liquid leak or spill could be significant. This includes Unusually Sensitive Areas of the environment (defined in 195.6), high population areas (urbanized areas identified by the Census Bureau), other populated areas (other areas of concentrated population defined by the Census Bureau), and commercially navigable waterways. See 49 CFR 195.450 for a complete definition.	IM Website - glossary
High consequence area (HCA) - hazardous liquid	A commercially navigable waterway, high population area, other populated area, or an unusually sensitive area.	195.450

Term	Definition	Definition Source
High population area	An urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.	195.450
Highly volatile liquid (HVL)	A hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276kPa (40psia) at 37.8 deg C (100 deg F).	195.2
Holiday	A discontinuity in a protective coating that exposes unprotected surface to the environment.	ANSI/NACE SP0502
Holiday detection	Testing a coating for holidays by using an instrument that applies a voltage between the external surface of the coating and the pipe.	GPTC
Hoop stress	The stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and produced by the pressure of the fluid or gas in the pipe. Hoop stress is a very critical factor in determining a pipe's pressure holding capabilities and thus its appropriate application. Hoop stress is calculated using Barlow's Equation (see definition).	GPTC
Hot pass	The second pass made on a weld. The hot pass immediately follows the root, or stringer bead pass and precedes the filler passes and cap weld.	
Hot tap	Hot taps are branch piping connections made to operating pipelines, mains, or other facilities while they are in operation. The branch piping is connected to the operating line, and the operating line is tapped while it is under gas pressure.	B31.8 2003
Housekeeping	Refers to keeping a work location free of debris and hazards that could contribute to accidents.	
Hydraulic gradient	Graphical relationship between pipeline pressure (head) and elevation along a pipeline. If the hydraulic gradient is plotted in feet of liquid or head against a profile illustrating elevation and distances between the discharge of one station and the suction at another station down the pipeline, it describes the pressure conditions along this particular line segment. The amount of slope of the plotted gradient is based upon the fluid's frictional losses between stations.	
Hydraulic head	The force exerted by a column of fluid expressed by the height of the fluid above the point at which pressure is measured. Although head refers to distance or height, it is used to express pressure, since the force of the fluid column is directly proportional to its height. Also called head or hydrostatic head.	
Hydrogen embrittlement	Embrittlement caused by the presence of hydrogen within a metal or alloy.	NACE/ASTM G193 Corrosion Terms
Hydrogen induced cracking	Stepwise internal cracks that connect adjacent hydrogen blisters on different planes in the metal, or to the metal surface.	NACE/ASTM G193 Corrosion Terms
Hydrogen stress cracking	Cracking of a metal or alloy under the combined action of tensile stress and the presence of hydrogen in the metal or alloy.	NACE/ASTM G193 Corrosion Terms
Hydrometer	An instrument used to determine the specific gravity of liquids.	

Term	**Definition**	**Definition Source**
Hydrostatic pressure	The force exerted by a body of fluid at rest; it increases directly with the density and the depth of the fluid and is expressed in psi or kPa. The hydrostatic pressure of fresh water is 0.433 psi per foot of depth (9.792 kPa/m). In drilling, the term refers to the pressure exerted by the column drilling fluid in the well bore. In a water-driven reservoir, the term refers to the pressure that may furnish the primary energy for production.	
Hydrostatic test (hydrotest)	Proof testing of sections of a pipeline by filling the line with water and pressurizing it until the nominal hoop stresses in the pipe reach a specified value.	NACE RP0502
Ignition temperature	The minimum temperature required to ignite gas or vapor without a spark or flame being present.	
ILI (inline inspection)	The inspection of a steel pipeline using an electronic instrument or tool that travels along the interior of the pipeline in order to locate corrosion and/or material defects.	NACE
ILI tools	Any of a variety of inspection devices designed to be run while the pipeline remains in service. These devices, or "pigs", measure and record the internal geometry, external or internal corrosion as well as provide information about pipe characteristics such as wall thickness and other pipe defects. Magnetic flux leakage, ultrasonic, calipers, and geometry are examples of smart tools. Also referred to as smart pigs.	
Impressed current	An electric current supplied by a device employing a power source that is external to the electrode system.	NACE/ASTM G193 Corrosion Terms
Impressed current anode	Anodes, typically made of graphite, carbon or high-silicon cast iron installed in either ground beds or deep wells drilled along the pipeline route, that provide sacrificial protection to another metal when electrically connected to a rectifier.	
Inactive pipeline	A pipeline that is not presently being used to transport gas or liquids, but continues to be maintained under Part 192 or 195. May also be called an idle pipeline. *(The Parts 192 and 195 regulations do not define "idle" pipe. Pipe is considered either active or abandoned.)*	GPTC
Incident Command System (ICS)	An emergency management system, most commonly used for large emergencies, whereby key decisions are made by a Unified Command group consisting of representatives of both the Federal and State Government, and the responsible party (in pipeline related events this would be the operator).	
Incorporated by reference	Specific versions (by revision date) of various organization or industry standards, specifications, or recommended best practices and approved, wholly or in part, for incorporation by reference into regulations.	192.7 195.3
Indirect inspection	Equipment and practices used to take measurements at ground surface above or near a pipeline to locate or characterize corrosion activity, coating holidays, or other anomalies.	ANSI/NACE SP0502
Inert gas	A gas that is non-explosive and non-flammable. Operators use inert gases for testing and purging pipelines. The most common inert gas is nitrogen. High concentrations of inert gases may cause asphyxiation.	

Term	Definition	Definition Source
Inhibitors	An additive used to retard undesirable chemical action in a pipeline or pipeline facility when added in small quantities.	
In-patient hospitalization	Inpatient hospitalization requires both hospital admission and at least one overnight stay.	Instructions for forms PHMSA F7000-1 (rev 11/2010) and PHMSA F 7100.2 (rev 11/2010)
In-plant piping system	Piping and devices that are located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other modes of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline.	195.2 195.406(b)
Instant - off potential	The structure-to-soil potential immediately after all CP current is interrupted and prior to polarization decay.	
Instant - on potential	The structure-to-soil potential immediately after CP current is applied and prior to polarization.	
Instrument piping	Pipe, valves and fittings used to connect instruments to main piping, to other instruments and apparatus, or to measuring equipment.	GPTC
Integrity management (IM)	A risk-based approach to improving pipeline safety. Integrated and iterative processes for assessing and mitigating pipeline risks in order to reduce both the likelihood and consequences of incidents or accidents. These management and analysis processes integrate all available integrity-related data and information to assess the risks associated with pipelines, and then implement additional risk control measures.	
Integrity management program	A set of safety management, analytical, operations, and maintenance processes that are implemented in an integrated and rigorous manner to assure operators provide protection for HCAs. While the rules provide some flexibility for an operator to develop a program best suited for its pipeline system(s) and operations, there are certain required features – called "program elements" – which each integrity management program must have.	https://primis.phmsa.dot.gov/comm/Im.htm
Interference	Ionic current discharged through the electrolytic path from a metallic structure due to the suppression with the CP system of that structure.	
Interference bond	An intentional metallic connection, between metallic systems in contact with a common electrolyte, designed to control electrical current interchange between the systems.	NACE SP0169
Interstate pipeline	Means a pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.	195.2
Intrastate pipeline	A pipeline or that part of a pipeline to which this part applies that is not an interstate pipeline.	195.2
Ion	An electrically charged atom or group of atoms.	
IR drop	The voltage drop across a resistance in accordance with Ohm's Law.	ANSI/NACE SP0502

Term	Definition	Definition Source
Jeep	A method of holiday detection using an instrument that applies a voltage between the external surface of the coating and the pipe.	GPTC
Joint	Refers to the connection between two lengths of pipe such as the weld joint for steel pipe and the heat fusion or glue joint for plastic pipe. Joint is also used as a slang term meaning a length of pipe i.e., joint of pipe.	
Laminar flow	Laminar flow describes the relatively straight travel path of the fluid molecules within the pipe. The flow velocity decreases with the distance from the center of the pipe. The velocity profile of a fluid in laminar flow is bullet shaped and concentric about the centerline. This shape accounts for the larger interface or commingling of batched streams of crude oils. Laminar flow conditions within a pipeline will also yield increased water dropout in low-lying areas.	
Launcher or receiver	Barrel-shaped appurtenance attached to a pipeline and able to be isolated from the pipeline pressure to facilitate launching pigs into the pipeline and receiving the pigs out of the pipeline.	
Leak test	A quality control check of the structural integrity of a pipeline performed by filling the line with a fluid, and applying a specified pressure for a prescribed period of time. Any ruptures or leaks revealed by the test must be properly repaired.	
Length	A piece of pipe as delivered from the mill. Each piece is called a length regardless of its actual dimension however, 40 feet is typical for larger diameter pipe. While this is sometimes called "joint," the term "length" is preferred.	GPTC (Interpretation 192 Appendix BII, August 21, 2008)
Life-of-facility documents	The documents relating to design, materials, construction, testing, repairs, and some corrosion records that must be maintained as long as the facility remains in service.	
Light surface oxide	A non-damaging form of corrosion.	GPTC
Line section	A continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and a block valve, or between adjacent block valves.	195.2
Liquefied natural gas (LNG)	Natural gas or synthetic gas having methane (CH 4) as its major constituent which has been changed to a liquid.	193.2007
Liquefied petroleum gas (LPG)	A gas containing certain specific hydrocarbons which have been changed to a liquid under moderate pressure at normal temperatures. Propane and butane are principal examples.	
Liquid	A state of matter, neither solid or gas, characterized by free movement of molecules among themselves, but without the tendency to separate or disperse to fill every space of a container.	
Low stress pipe	A hazardous liquid pipeline that is operated in its entirety at a stress level of 20% or less of the specified minimum yield strength of the line pipe. *(Low stress pipelines have limited jurisdiction by the Office of Pipeline Safety. Additional information regarding jurisdiction can be found in §195.12.)*	195.2
Lower explosive limit (LEL)	The lower limit of flammability for a gas expressed as a percent, by volume, of gas in air.	GPTC

Term	Definition	Definition Source
Mainline valves	Valves positioned at locations along the pipeline system that can be closed down to isolate a line section.	
Manometer	An instrument used to measure pressures. It consists of a tube in the shape of a U, partially filled with liquid of suitable density, usually water. When sources of different pressure are connected to each end of the manometer, the liquid is pushed up in the low-pressure side of the manometer, and the difference in liquid level between the two sides of the U is an indication of pressure difference.	
Maximum allowable hoop stress - liquid	The maximum hoop stress permitted for the design of a piping system.	
Maximum operating pressure (MOP)	The maximum pressure at which a pipeline or segment of a pipeline may be normally operated under Part 195. *(See §195.406 for further guidance)*	195.2
Mechanical damage	Any number of types of anomalies in pipe, including dents, gouges, and metal loss, caused by the application of an external force.	ANSI/NACE SP0502
Meter	Any mechanical device used to measure the volume throughput of natural gas or petroleum liquids.	
Microbiologically influenced corrosion (MIC)	Localized corrosion resulting from the presence and activities of microorganisms, including bacteria and fungi.	ANSI/NACE SP0502
Mill scale	The oxide layer formed during hot fabrication or heat treatment of metals.	NACE/ASTM G193 Corrosion Terms
Miter joint	A joint made by cutting the pipe at an angle, then joining the pieces together to form a bend.	
Multi-jurisdictional tank	A tankage facility having both terminal and breakout tanks. This type of facility is subject to the dual jurisdiction of both EPA and DOT.	
Navigable waters	The waters of the United States, including the territorial sea and such waters as lakes, rivers, streams; waters which are used for recreation; and waters from which fish or shellfish are taken and sold in interstate or foreign commerce.	194.5
Navigable waterway	Navigable waterways are those waterways "where a substantial likelihood of commercial navigation exists. Further guidance in determining the navigable waterways is available in a geographic database of navigable waterways in and around the United States called the National Waterways Network. The database includes commercially navigable waterways and noncommercially navigable waterways. The database can be downloaded at: http://www.ndc.iwr.usace.army.mil/db/waternet/data/WATERTL1.DBF A map of the commercially navigable waterways portion of the national Waterways Network database is in the National Pipeline Mapping System.	Federal Register /Vol. 65, No. 175 / Friday, September 8, 2000, page 54441

Term	Definition	Definition Source
Needle valve	A small valve used to regulate small amounts of gas or fluid flow. It contains a pointed plug or needle resting in an orifice or tapered orifice in the valve body. By adjusting the needle's position within the seat or orifice, small amounts of gas or liquids are finely regulated. Needle valves are typically used on instrument, control, or sampling pipe.	
Night cap	A plug or cap attached to the open end of a pipe or pipeline to keep foreign objects or matter out of the pipe. These "night caps" are often used on construction or repair jobs and are usually installed at the end of a workday or shift.	
Nominal wall thickness	The wall thickness listed in the pipe specifications.	195.2
Non-critical interference bond	A metallic connection between adjacent buried structures which allow current flow that is not detrimental to the operator of the pipeline.	
Nondestructive testing (NDT)	Testing in which the part being tested is not rendered unusable. NDT techniques include radiography (X-ray), ultrasonic, magnetic particles, dye penetrate, or ammonium persulfate.	
NPMS	National Pipeline Mapping System	
Offshore	Beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.	191.3 192.3 195.2
Oil Pollution Act of 1990 (OPA 90)	Public Law 101 to 380 passed in 1990, substantially expanding existing legislation relating to the discharge of oil into navigable waters and onshore locations. Out of this law came the CFR Part194 regulations concerning Oil Spill Response Plans for onshore pipelines.	
Onshore oil pipeline facilities	New or existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of oil located in, on, or under, any land within the United Stated other than submerged land.	194.5
Operating stress	The stress imposed on a pipe or structural member under normal operating conditions.	GPTC
Operator	A person who owns or operates pipeline facilities.	195.2
Other populated area	A place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.	195.450
Outer Continental Shelf (OCS)	Means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.	192.3 195.2
Overpressure protection (OPP)	The devices or equipment installed for the purpose of preventing pressure in a pipe system or other facility from exceeding a predetermined limit.	GPTC
Oxidation	(1) Loss of electrons by a constituent of a chemical reaction. (2) Corrosion of a metal that is exposed to an oxidizing gas at elevated temperatures.	NACE/ASTM G193 Corrosion Terms
Padding	The placing of material free of any hard objects (rocks, etc.) below, around, and above the pipe during backfill in order to protect the pipe surface from puncture or excessive abrasion.	

Term	Definition	Definition Source
Parallel encroachment	Parallel encroachment describes that portion of the route of a pipeline system or main that lies within, or runs in a generally parallel direction, with the rights-of-way of a road, street, highway, railroad, or other utilities.	GPTC
Parts per million (ppm)	A unit typically used to express chemical concentration, one part of the chemical in each one million (1,000,000) parts of the base material.	
Performance language	A regulatory approach that prescribes an end result (i.e., a certain level of pipeline safety) but leaves the method or how to achieve it up to the operator's discretion. This approach is often used to allow each operator to accommodate their individual differences in equipment, procedures, and operational circumstances.	Interpretation PI-89-023
Person	Any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.	192.3 195.2
Personal protective equipment (PPE)	Personal protective equipment is equipment that protects the individual who wears it by placing a barrier between that individual and a potential or known hazard. Examples of PPE include protective eyewear, face shields, masks, gloves, boots, hats, clothing, and respirators.	
Petrochemical	Chemicals derived from processing or refining crude oil or natural gas.	
Petroleum	Crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.	195.2
Petroleum product	Flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.	195.2
pH	The negative logarithm of the hydrogen ion concentration in a solution. *(The measurement of the hydrogen ion concentrations in solution. pH is a 14-point scale that measures the acidic or alkalinity value of a substance: strong acids have low pH values and strong bases have high pH values, with a value of 7 being considered neutral, anything less than 7 is considered an acid and greater than 7 are alkaline or bases).*	NACE/ASTM G193 Corrosion Terms
Pig	Any mechanical device inserted and run inside a pipeline.	
Pipe or line pipe	A tube, usually cylindrical, through which a hazardous liquid or carbon dioxide flows from one point to another.	195.2
Pipeline environment	Includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other know conditions that could affect the probability of active corrosion.	192.3 195.553
Pipeline facility	New and existing pipeline, rights-of-way, and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide.	195.2
Pipeline or pipeline system	All parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.	195.2

Term	Definition	Definition Source
Pipe-supporting element	A pipe-supporting element consists of fixtures and structural attachments.	
Pitting	Localized corrosion of a metal surface that is confined to a small area and takes the form of cavities called pits.	NACE/ASTM G193 Corrosion Terms
Polarization	The change from the open circuit potential as a result of current across the electrode/electrolyte interface.	NACE SP0169
Polarized potential	The potential across the structure/electrolyte interface that is the sum of the corrosion potential and the cathodic polarization.	NACE SP0169
Positive displacement pump	A self-priming pump where the delivered capacity is virtually constant regardless of discharge pressure. There are two types of positive displacement pumps: reciprocating (i.e., piston or plunger) pumps and rotating (i.e., screw-type) pumps. Positive displacement pumps are known for their ability to generate very high pressures but are usually limited in their throughput capacities.	
Pounds per square inch (PSI)	The unit of pressure or measure of force on a given area. Within the oil and gas industry, psi normally refers to the pressure of the gas or product contained within the pipeline or pressure vessel.	
Pounds per square inch absolute (PSIA)	The pressure expressed in pounds exerted on one square inch of surface area. The absolute refers to the total pressure sensed including the surrounding atmospheric pressure.	
Pounds per square inch gauge (PSIG)	The pressure expressed in pounds exerted on one square inch of surface area. The designation "gauge" indicates the readings are already adjusted or biased to ignore the surrounding atmospheric pressure which is 14.7 psi at sea level. If a PSIG type of gauge were not connected to any pressure source, it would read zero even though it is actually sensing 14.7 psi at sea level.	
Pressure	The force on a given area expressed in pounds per square inch (PSI) or its metric equivalent of kilo Pascal's (kPa).	
Pressure test	A quality control check of the structural integrity of a pipeline performed by filling the line with a liquid or gas, and applying a specified pressure for a prescribed period of time. May be called a strength test. If water is used as the testing medium, it may be called a hydrotest.	
Private right-of-way	A land use grant obtained through negotiations between the private landowner and the pipeline company. The grant permits the pipeline operator to install and maintain the pipeline buried within or traversing over private property.	
Production facility	Piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or carbon dioxide from the ground or from facilities where CO_2 is produced, and preparing it for transportation by pipeline. This includes piping between treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)	195.2

Term	Definition	Definition Source
Protective coating	A coating applied to a surface to protect the substrate from corrosion.	NACE/ASTM G193 Corrosion Terms
Prototype	The original pattern on which all similar subsequent fittings of the kind and size are based.	Interpretation PI-73-021
Pump	A mechanical device used to move liquid substances from one location to another. Pumps may be used singularly or in groups.	
Purging	The act of replacing a gas, air or liquid with another fluid in a container or pipeline to prevent the formation of an explosive mixture.	
Qualified	An individual has been evaluated and can (a) perform assigned covered tasks and (b) recognize and react to abnormal operating conditions	192.803 195.503
Qualified welder	A welder who has demonstrated the ability to produce sound welds meeting the requirements of 49 CFR, and is qualified under an operators welding program. DOT Parts §§192.227, 192.229, and 195.222 specify under what conditions and how often a welder must be re-qualified.	
Qualified welding procedure	A detailed and destructively tested method by which sound welds can be produced. These procedures must be qualified under section 5 of API 1104 or section IX of the ASME Boiler and Pressure Vessel Code.	
Radiography	A variety of processes of non-destructive testing that use electromagnetic radiation to produce a record, usually a film, to view a material and find defects. Examples of electromagnetic radiation are X-ray and gamma rays.	
Reciprocating pump	A mechanical device which move fluids by means of a piston or plunger operating from a crankshaft.	
Rectifier	A device used to convert alternating current (AC) to direct current (DC).	
Reference electrode (half cell)	An electrode whose open-circuit potential is constant under similar conditions of measurement, which is used for measuring the relative potentials of other electrodes.	NACE SP0169
Regulator	A device used to control the pressure of the pipeline system to which it is connected.	
Relief valve	A mechanical device designed to open automatically and release excess pressure above a preset pressure limit.	
Remote control valve (RCV)	A valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.	195.45
Resistance bond	A metallic path, where the amount of current is controlled by a permanent or adjustable resistance, installed to provide a return path for cathodic protection current thus to prevent corrosion due to interference or stray current.	
Reverse-current switch	A bond designed and constructed such that CP current can pass in only one direction.	
Right-of-way	A general term denoting land, property or interest therein, usually in a strip, acquired for or devoted to a specific purpose such as a highway or pipeline.	GPTC

Term	Definition	Definition Source
Riser	A general term for vertical runs of piping regardless of the size or application.	
Risk management	The systematic application, by the owner or operator of a pipeline facility, of management policies, procedures, finite resources, and practices to the tasks of identifying, analyzing, assessing, reducing, and controlling risk in order to protect employees, the general public, the environment, and pipeline facilities.	49 U.S.C. 60101
Root pass	See "stringer pass".	
Rotary pump	A mechanical device consisting of a rotating shaft turning a screw, cam, gear, or plunger within a fixed casing.	
Rupture	A rapid bursting open of a container such as a segment of pipeline.	
Rupture disc or rupture pin	A onetime use, non-reclosing, sacrificial pressure relief device that protects a vessel, equipment or system from over pressurization at a manufactured predetermined level.	
Rural area	Outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area, such as a subdivision, a business or shopping center, or community development.	195.2
Sample piping	Pipe, valves and fittings used for the collection of samples of fluids.	
Scraper	Any device that is used to remove debris or deposits (such as scale, rust or paraffin) from tubing, casing, rods, flow lines, or pipelines.	GPTC
Seamless pipe	A wrought tubular product made without a welded seam. It is manufactured by hot working steel or, if necessary, by subsequently cold finishing the hot-worked tubular product to produce the desired shape, dimensions and properties.	GPTC
Secondary stress	Stress created in the pipe wall by loads other than internal gas or fluid pressure. Examples are backfill loads, traffic loads, beam action in an unsupported span, loads at supports, blasting, and at connections of improperly supported pipe.	GPTC
Shallow anode (conventional ground) bed	One or more anodes installed either vertically or horizontally at a nominal depth of less than 50 feet for the purpose of supplying CP current.	NACE/ASTM G193 Corrosion Terms
Shielding	High resistance or non-conducting material preventing CP current from reaching the structure, or low resistance material diverting the current away from the structure to be protected.	
Shorted pipeline casing	A casing that is not electrically isolated from the carrier pipe. Generally this term is used for casings that are in direct metallic contact with the carrier pipe.	
Smart pig	Any of a variety of inspection devices designed to be run while the pipeline remains in service. These devices, or "pigs", measure and record the internal geometry, external or internal corrosion as well as provide information about pipe characteristics such as wall thickness and other pipe defects. Magnetic flux leakage, ultrasonic, calipers, and geometry are examples of smart tools (also referred to as ILI tools).	
Solvent cleaning	Removal of oil, grease, dirt, soil, salts, and contaminants using organic solvents or other cleaners such as vapor, alkali, emulsion, or steam.	NACE/ASTM G193 Corrosion Terms

Term	**Definition**	**Definition Source**
Sound engineering practice	Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.	NACE RP0502
Sour	Fluids containing sulfur compounds or entrained hydrogen sulfide (H_2S) at concentration which may cause corrosion and require additional processing.	
Specific gravity	The ratio of the weight of a given volume of a substance at a given temperature to the weight of a standard substance at the same temperature.	NACE
Specified minimum yield strength (SMYS)(liquid)	The minimum yield strength, expressed in p.s.i. (kPa) gage, prescribed by the specification under which the material is purchased from the manufacturer.	195.2
Static electricity	The buildup of an electric charge on the surface of objects that remains on an object until it is discharged.	
Stationing (map stations, mileposts)	A measure of length used to identify locations along the pipeline which provides a geospatial reference for pipeline features and construction. . Stationing is typically measured in feet, usually indicated as X+XX. Generally, the beginning of the pipeline route is designated as zero, and station values increase along the route. Some operators use mile posts as a method of stationing.	
Steel	An iron-base alloy, malleable in some temperature ranges as when initially cast, containing manganese, carbon and often other alloying elements.	GPTC
Stray current	Current which flows through paths other than the intended circuit.	NACE SP0169
Strength test	A quality control check of the structural integrity of a pipeline performed by filling the line with a liquid or gas, and applying a specified pressure for a prescribed period of time. May be called a pressure test. If water is used as the testing medium, it may be called a hydrotest.	
Stress	The resultant internal forces within a material that resists change in the size or shape of the material when acted on by external forces.	GPTC
Stress corrosion cracking (SCC)	The formation of cracks in metallic pipe, typically in a colony or cluster, as a result of the interaction of tensile stress, a corrosive environment, and a susceptible material.	GPTC
Stress level	The level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.	195.2
Stringer pass	The initial welding pass to join two pieces of pipe together. Also called root pass.	
Stringing	The process of delivering and distributing line pipe or components where and when it is needed on the right-of-way during construction activities.	
Structural attachments	Components which are welded, bolted, or clamped to the pipe, such as clips, lugs, clamps, clevises, straps and skirts.	

Term	Definition	Definition Source
Subject matter experts (SMEs)	Persons knowledgeable about design, construction, operations, maintenance, or characteristics of a pipeline system. Designation as an SME does not necessarily require specialized education or advanced qualifications. Some SMEs may possess such expertise, but detailed knowledge of the pipeline system gained by working with it over time can also make someone an SME. SMEs may be employees, consultants, contractors, or any suitable combination of these.	GPTC
Sulfide stress cracking	Cracking of a metal under the combined action of tensile stress and corrosion in the presence of water and hydrogen sulfide.	NACE/ASTM G193 Corrosion Terms
Supervisory control and data acquisition (SCADA)	Means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.	192.3 195.2
Surge pressure	Pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.	195.2
Sweet crude	Crude oil that contains little or no sulfur compounds or entrained H_2S.	
Tank farm	A group of tanks used to store crude oil and refined products.	
Tapping tee or tapping saddle	A tee fitting used to connect an in-service pipeline used to make a new connection.	
Tensile strength	The highest unit tensile stress (referred to the original cross section) that a material can sustain before failure (psi)	GPTC
Test station (test point)	An aboveground electrical connection to an underground pipe or structure where pipe-to-soil potentials are taken to monitor CP.	
Third-party damage	Damage to pipelines and other facilities that can occur during excavation, digging, or other activities by persons not affiliated with the pipeline operator or their contractors.	
Toxic product	"Poisonous material" as defined by 173.132 Class 6, Division 6.1 - Definitions of this chapter.	195.2
Trench	A long ditch cut into the ground dug by a backhoe or by a specialized digging machine such as a trencher, for the purpose of installing a pipeline.	
Trunk line	A piping system used to transport natural gas or liquids from the producing areas of the country to the refineries, terminal, or interconnections.	APGA
Tubing	Smaller diameter pipe (usually stainless steel or copper) with diameter usually less than 1/2 inch and is generally used as instrumentation or control piping, to sense pipeline conditions for instrumentation monitoring and control.	
Turbulent flow	The chaotic and random flow patterns that occur as fluid moves through a pipeline. Although it requires more energy, hazardous liquid pipelines prefer to operate in the turbulent flow mode because less commingling or interface occurs between batches. The haphazard molecular flow pattern also keeps sediment and water mixed up or suspended in the flow stream.	
Ultimate strength	The maximum stress that a material can sustain.	

Term	Definition	Definition Source
Ultrasonic testing	A non-destructive inspection method consisting of an instrument with a probe that generates high-frequency sound waves and measures the wave's reflection off the pipe inner wall. Ultrasonic probes must be "coupled" to the pipe with some sort of liquid, and is used to determine the condition of the pipeline facilities.	
Underground storage	The utilization of subsurface facilities for storing hydrocarbon fluids which can later be withdrawn as required for a variety of operational reasons. Storage facilities can include natural geologic features such as depleted hydrocarbon reservoirs, salt domes or aquifers or manmade caverns.	
Union	A specialized threaded fitting used to couple two joints of threaded pipe together, without having to turn or dismantle either run of pipe.	
Unusually sensitive area	A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as identified under 195.6.	195.2
Upper explosive level (UEL)	The maximum amount of airborne fuel that can be present in an air-fuel mixture and still be explosive. An air- fuel mixture above the UEL is considered too rich to ignite.	
Upstream	The direction the fluid is coming from in regard to a reference point. With compressor and pump stations, upstream would be the suction side of the facility.	
Valve	A mechanical device used to control the flow of gas or liquid. A valve can be used solely for fully open or closed applications, to control the direction of flow, or used to throttle flow or regulate pressure. Valves types include plug valves, ball valves, globe valves, and gate valves.	
Valve box	A protective container installed around an underground valve to allow operation or maintenance access to underground pipeline valves.	
Vault	An underground structure which may be entered, and which is designed to contain piping and piping components such as valves or pressure regulators.	GPTC
Viscosity	The resistance to flow in a particular fluid.	
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.	NACE SP0169
Warning tape	A tape installed above a pipeline or tracer wire to warn excavators of the proximity of the pipeline.	
Welding	A method of joining metal together using heat to fuse the pieces. Examples of welding processes are: submerged metal arc welding, oxyacetylene welding, and electrical resistance welding.	
Wireline or tethered pig	A mechanical device run inside an out of service pipeline between one or more openings cut in the pipeline. Wireline pigs are tethered to a wireline cable, and are propelled by pulling on the cable.	
X-ray	A specific radiographic method of non-destructive testing that uses X-rays to produce a film that is used to analyze the quality of welded joints in metallic pipe. See radiography.	
Yield strength	The yield strength is the stress level at which a material exceeds its elastic limits and the material begins to permanently deform.	
You	The operator.	195.553

Enforcement Guidance	O&M Part 195
Revision Date	12-07-2011
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-ZZ-035 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-ZZ-033 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-ZZ-024 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.

<table>
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<td>Advisory Bulletin/Alert Notice Summaries</td>
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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.
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	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	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.
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	12-07-2011
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 insure 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-ZZ-030 Date: 01-26-1983** Section 195124 requires that closures be designed in accordance with the ASME Boiler and Pressure Vessel Code. Section 195.426 requires certain safety devices on scraper traps. These two sections currently require all of the safety provisions recommended in your memo. Further, §195.402(a) and (c)(3) are sufficiently broad to require operating procedures for scraper traps.
Advisory Bulletins/Alert Notice Summaries	**Advisory Bulletin ADB 09-03, Operator Qualification (OQ) Program Modifications.** In order to clarify the requirements of 49 CFR 192.605(a) and 195.402(a) as they apply to OQ and written OQ program reviews, See 195.505 1a. Operators' review of their OQ Plan in accordance with §§ 192.605(a) and 195.402(a) should be conducted in connection with their reviews of their O&M Plans every 15 months, but at least once each calendar year. 1b. Operators' ''periodic review of work'' being done in accordance with §§ 192.605(b)(8) and 195.402(c)(13), should include evaluation of OQ procedure effectiveness to identify where corrective actions are needed to address deficiencies. 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	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.
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	12-07-2011
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	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
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Examples of a Probable Violation	
Examples of Evidence	
Other Special Notations	

Enforcement Guidance	O&M Part 195
Revision Date	12-07-2011
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 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-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-ZZ-022 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-ZZ-021 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 guidance, 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. A tie to the change management process should show the procedure modification that was made in response to the analysis. 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. Observation of operator qualification training where an operation or maintenance task is performed is not, by itself, adequate to satisfy the requirements of §195.402(c)(13). 32. 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). Section 195.402(c)(13) "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]." CO/CP
Examples of a Probable Violation	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.
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	12-07-2011
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. Ongoing management of change process
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 setpoints 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	1. There is no written procedure or the operator did not follow the procedure.
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	12-07-2011
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-ZZ-033 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 to assure 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	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.
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	12-07-2011
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 Violation	1. There is no written procedure or the operator did not follow the procedure.
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	12-07-2011
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	Original Code Document, 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** For companies that have non-U.S. based emergency response teams, PHMSA will accept non-U.S. emergency response training for purposes of assessing compliance with Parts 194 and 195 in the same way we would accept and review a U.S. based training program during a compliance audit. The training program must provide all the required training and you must adequately document the training in records

	available for inspection in the U.S. by PHMSA at reasonable times.
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	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 being trained on the emergency plan when performing an activity where an emergency might occur.
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	12-07-2011
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-ZZ-063 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	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.
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	12-07-2011
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 Recommended Practice 2003, unless the operator notes in the procedural manual (§195.402(c)) why compliance with all or certain provisions of API Recommended Practice 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 Publication 2026. After October 2, 2000, the operator must review and consider the potentially hazardous conditions, safety practices and procedures in API Publication 2026 for inclusion in the procedure manual (§195.402(c)).
Origin of Code	Original Code Document, 64 FR 15926, 04-02-1999
Last Amendment	
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 Publication 2026, ''Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service'' (2nd edition, April 1998, reaffirmed June 2006).
Guidance Information	1. The operator must have written procedures.
Examples of a Probable Violation	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.
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	12-07-2011
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 B31.8, 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. 195-65, 63 FR 59475, 11-04-1998.
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), as long as 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. 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
Examples of a Probable Violation	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 any equipment 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.

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	12-07-2011
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	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.

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	12-07-2011
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 particular 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-ZZ-014 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-ZZ-010 Date: 06-06-1973** Direction of flow does not need to be shown on a line marker. **Interpretation: PI-ZZ-008 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, as long as 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. Final Order Guidance: **a. 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	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.
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	12-07-2011
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-ZZ-050 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-ZZ-049 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-ZZ-047 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-ZZ-041 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-ZZ-025 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-ZZ-013 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	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.
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	12-07-2011
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/Alert Notice Summaries	
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. 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	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.
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	12-07-2011
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 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.

	Respondent is correct that neither the pipeline safety statute nor part 195 regulations define a "mainline" or "mainline valve." Without a definition of a mainline valve, a common sense approach is needed. The list in §195.260 has been interpreted as referring to examples of mainline valves. Section 195.260 (c) uses the term mainline but only to provide that valves located on a mainline have to be located at certain points along that line. This requirement does not imply that only valves listed in §195.260 are mainline valves. The examples in §195.260 are consistent with ASME/ANSI. The ASME B31.4 Code provides that mainline valves are to be located at certain locations critical to the safe operation of a pipeline system. Regulations must be read in entirety to ascertain the true nature of the intent and purpose sought to be accomplished. The inspection requirements of Part 195 are not based upon system design but on safety needs. In this case, after further review and consideration of the purpose that the 158 valves serve to the operation of Respondent's pipeline system, OPS has determined that there were 48 missed mainline valve inspections and not 158 as originally proposed. The valves in question are used for station isolation, segment isolation, water crossing isolation, and lateral isolation. These valves, which are integral to the safe operation of the pipeline system, should have been classified and treated as mainline valves and inspected according to the requirements of §195.420(b). Respondent's records do not show that inspections were conducted within the required intervals. CP
Examples of a Probable Violation	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. 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. 9. 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)

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	12-07-2011
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-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-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’’ (October 20, 2006). API Standard 1104, ‘‘Welding of Pipelines and Related Facilities’’ (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

Examples of a Probable Violation	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.
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	12-07-2011
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	1. The lack of a procedure is a violation of 195.402. 2. The lack of records is a violation of 195.404. 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.
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	12-07-2011
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	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.
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	12-07-2011
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 Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. 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 Recommended Practice 2350. However, operators need not comply with any part of API Recommended Practice 2350 for a particular breakout tank if the operator notes in the manual required by §195.402 why compliance with that part is not necessary for safety of the tank. 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. 195-66, 64 FR 15926, 04-02-1999.
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 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. 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. 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
Examples of a Probable Violation	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).
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	12-07-2011
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 fire fighting 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: a. Generally OSHA and NFPA require: b. Portable extinguishers …shall be visually inspected monthly. c. The employer shall assure that portable fire extinguishers are subjected to an annual maintenance check. …. d. A trained person …shall service the fire extinguishers not more than 1 year apart e. Portable extinguishers must be subjected to a hydrostatic pressure test between every 5 and 12 years depending on the agent.

	f. 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	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 fire fighting 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.
Examples of Evidence	1. Fire fighting 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	12-07-2011
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 aboveground breakout tanks according to API Standard 653 (incorporated by reference, see § 195.3). However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3). (c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510. (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. 195-94, 75 FR 48593, 08-11-2010.
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 an alternative to the above requirements in API 653 section 6.4.2 an owner-operator may establish the internal inspection interval using risk based inspection (RBI) procedures as shown in API 653 section 6.4.3. iv. 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 butylenes. 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 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 Violation	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. 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. 14. Repads are sharp edged.
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	12-07-2011
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 posted on each side of a pump station and/or breakout tank facility. 3. Signs must be legible. 4. Verify the accuracy of the operator's name on the sign. 5. Verify that the emergency phone number posted on the signs is correct. 6. Stickers applied to signs to update certain information are satisfactory, as long as they are permanently applied and remain legible. 7. 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	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. 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.
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	12-07-2011
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-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-ZZ-021 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.** ***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 **b.** ***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	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.

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	12-07-2011
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	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.
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	12-07-2011
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/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, if used, 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	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.

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	12-07-2011
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 1130 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	
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-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	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.

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	