Operations & Maintenance Enforcement Guidance

Part 192 Subparts L and M

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Introduction

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

The Federal pipeline safety regulations (49 CFR Parts 190-199) discussed in this guidance document contains legally binding requirements. This document is not a regulation and creates no new legal obligations. The regulation is controlling. The materials in this document are explanatory in nature and reflect PHMSA's current application of the regulations in effect at the time of the issuance of the guidance 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
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
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).	
Adhesive joint	A joint made on certain types of plastic piping by the use of an adhesive substance which forms a bond between the mating surfaces without dissolving either one of them.	GPTC
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).	

Term	Definition	Definition Source
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
Amphoteric metal	A metal that is susceptible to corrosion in both acidic and alkaline environments.	NACE/ASTM G193 Corrosion Terms
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
Anodeless riser	A plastic pipe sheathed inside a protective steel metallic casing. The steel-cased plastic pipe protrudes from the soil and is part of the service line carrying gas to the customer meter. An anode is not required in this instance because the plastic pipe contains the gas pressure and is not susceptible to the typical corrosive processes.	
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.	
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.	
Barhole	A small diameter hole in the ground made by a plunger bar or probe. These holes are made along the route of a gas pipeline to check the subsurface soil for an indication of gas accumulations due to leaks or to check the depth of pipe.	
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).	

Term	Definition	Definition Source
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.	
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
Blowdown	The depressurizing of a natural gas pipeline to facilitate maintenance on the pipeline, and is accomplished by opening a valve and allowing the gas to escape to atmosphere, usually through a vertical pipe or "stack".	
Bond	A connection, usually metallic, that provides electrical continuity between structures that can conduct electricity.	NACE SP0169
Bottle	A gas tight structure completely fabricated from pipe with integral drawn, forged end caps and tested in the manufacturer's plant (per ASME guidelines).	GPTC
Bottle-type holder	Any bottle or group of interconnected bottles buried underground installed in one location and used for the sole purpose of storing gas.	GPTC
Branch service line	A distribution line that delivers gas to an end user is considered a service line if it serves a single property, two adjacent properties, or an assembly containing multiple meters. If two properties are not adjacent, the pipe from the branch and upstream of that point becomes the main.	
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).	
British thermal unit (BTU)	The quantity of heat required to raise the temperature of one pound of water 1° F under standard pressure. BTU values of gas indicate the amount of heat a given unit of gas will provide and helps to compare the heating values of different gases.	
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
Business district	A 'business district' is an area marked by a distinguishing characteristic of being used in the conducting of buying and selling commodities and service, and related transactions. A 'business district' would normally be associated with the assembly of people in shops, offices and the like in the conduct of such business.	Interpretation PI-72-038

Term	Definition	Definition Source
Caliper pig	A mechanical device used to measure the internal diameter of a pipeline.	
Cap pass	The final pass of the welding process.	
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. 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.	GPTC
Casing	A pipe designed and installed to surround and protect a pipeline from external stresses and damage.	
Cast iron	An unqualified term that applies to gray cast iron which is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed through the metal. Because the carbon flakes do not bond with the ferrous material on the molecular level, the metal is brittle and susceptible to stress cracking under higher pressure situations.	GPTC
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
Centering	The process of investigating and approximating a leak location by determining the perimeter of the migrating gas, and locating the area that has the highest gas concentration.	
Centrifugal compressor	Mechanical devices used to boost the pressure of the gas at key locations on transmission pipeline system. Centrifugal compressors are typically used in higher flow applications and impart the rotational energy provided by their prime movers to the gas to move it along within the pipeline.	
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
Chiller	A chiller is generally a heat exchanger, designed to remove thermal energy or heat from a gas flow stream.	
City gate	A location at which gas may change ownership from one party to another (e.g., from a transmission company to a local distribution company), neither of which is the ultimate consumer. May also be referred to as a gate station or town border station.	
Class 1 location	(i) An offshore area; or (ii) Any class location unit that has 10 or fewer building intended for human occupancy	192.5(b)(1)

Term	Definition	Definition Source
Class 2 location	Any class location unit that has more than 10 but fewer than 46 building intended for human occupancy.	192.5(b)(2)
Class 3 location	(i) Any class location unit that has 46 or more buildings intended for human occupancy; or (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (the days and weeks need not be consecutive.)	192.5(b)(3)
Class 4 location	Any class location unit where buildings with four or more stories above ground are prevalent.	192.5(b)(4)
Class location unit	An onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) of a pipeline.	192.5
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.	
Combustible gas indicator (CGI)	A device used to detect flammable gas concentrations. A 2 to 3 foot probe rod and hose assembly is normally attached to an electronic unit that draws in an air sample by squeezing a rubber bulb.	
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.	
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."	
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®.	
Compressed natural gas	Natural gas stored inside containers at a pressure greater than atmospheric air pressure. CNG is normally placed in pressure containing vessels (bottles) where it can be used as a portable fuel source (i.e., in CNG vehicles and other applications not attached to a pipeline).	

Term	Definition	Definition Source
Compressor station	Any combination of facilities which supplies the energy to move gas at increased pressure from production fields, in transmission lines, or into storage. Compressor stations are strategically placed along the pipeline to boost the pressure to maintain required pressures and flow rates. Typical components found at gas compressor stations include: piping manifolds, coolers, valves, reciprocating or centrifugal compressors, prime movers (electric motors, gas engines, gas turbines), and local controls and instrumentation, and may include liquid separation and collection facilities, as well as pigging facilities.	
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.	
Confirmatory direct assessment	An integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.	192.903
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
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 segment or covered pipeline segment	A segment of gas transmission pipeline located in a high consequence area	192.903
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	

Term	Definition	Definition Source
	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.	
Curb valve	A valve installed for the purpose of shutting off the gas supply to a building. It is installed below grade in a service line at or near the property line and is operated by use of a removable key or specialized wrench. The valve is normally installed with a protective curb box or standpipe over or around it for quick subsurface access.	GPTC
Current	The flow of electrons in a circuit, measured in amperes (amps).	
Customer meter	A device that measures gas delivered to a customer from consumption on its premises.	192.3
Customer regulator	A device that limits and maintains a set pressure to the customer. This pressure controlling device is normally installed just upstream of the customer meter.	
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	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 - gas	Based on Barlow's Equation, the 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 gas pipeline design pressures, additional factors of F(class design factor as found in §192.111), E (longitudinal joint factor as determined in §192.113) and T (temperature derating factor as found in §192.115) are used, which makes the final gas design formula P=(2St)/D) x F x E x T.	192.105 Interpretation 192.106(6), July 25, 1973
Destructive testing	A physical testing process (such as a burst or a tensile test) during which the specimen being tested is rendered unusable.	
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	192.933 195.56(a) 195.452

Term	**Definition**	**Definition Source**
	and195.56(a)). However, for integrity Management (§§192.933 and 195.452) there is no distinction between discovery and determination.	
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.	
Direct sales lateral	A pipeline that transports gas directly from a transmission line to a large volume customer such as a factory or power plant. This pipeline is connected upstream from a distribution center or directly off of a transmission line.	Interpretation PI 89-019
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.	
Distribution line	A pipeline other than a gathering or transmission line. A pipeline that carries or controls the supply of natural gas from a town border or city gate and moves the gas to the customer.	192.3
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.	
Drip type odorizer	Equipment for introducing odorant from a storage tank directly into a gas stream through a gravity flow system. The odorant may be regulated by the orifice float valves or rotameters.	
Ductile (nodular) iron	A cast ferrous material in which the free graphite (carbon) present is in a spherical form rather than a flake form as in cast iron. These round shaped carbon elements cause ductile iron to be more malleable than cast iron, yet retain its toughness. These desirable properties of ductile iron are achieved by means of chemistry and a specialized heat treatment of the castings.	GPTC

Term	Definition	Definition Source
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.	
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 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.	
Emergency valve	For gas transmission operations, an emergency valve is any valve that might be required during any emergency. For gas distribution operations, an emergency valve is any valve which may be necessary for the safe operation of a distribution system.	192.745 192.747

Term	Definition	Definition Source
Environment	The surroundings or conditions (physical, chemical, mechanical) in which a material exists.	NACE/ASTM G193 Corrosion Terms
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
Excess flow valve (EFV)	A device that is installed in a gas pipeline or service line to automatically restrict or shut off the gas flow through the line when the flow exceeds a predetermined limit.	GPTC
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.	
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
Farm tap	A low volume service connection, generally off a high-pressure transmission line, providing gas to a customer in a rural location often provided as part of a right-of-way agreement.	
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.	
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.	
Flame ionization	A device used to detect flammable gas concentrations. Sample vapors are drawn in and subjected to a high-temperature filament where the gases are ionized to indicate the concentration of combustible gases.	
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.	
Flaring	The venting and igniting of flammable vapors or gas from a pipeline.	
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.	
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
Fusion	A process of joining plastic pipe segments by melting the plastic polymers at the two ends with heat to an extent where they will molecularly bond when pressed together. Depending on the type and size of pipe and the fusion machine used, precise temperatures, pressures, and time of cooling prior to releasing the joint from the fusion machine are all critical to producing an acceptable joint.	
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

Term	**Definition**	**Definition Source**
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.	
Gas	Gas is considered natural gas, flammable gas, or gas which is toxic or corrosive. *(In general, gas refers to a fluid in the vapor state of a substance.)*	192.3
Gate station	A location at which gas may change ownership from one party to another (e.g., from a transmission company to a local distribution company), neither of which is the ultimate consumer. In this instance, the gas is purchased for the sole purpose of resale. A gate station is also referred to as city gate station or town border station.	
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 (gas)	A gathering line is a pipeline that transports gas from a current production facility to a transmission line or main. *(Gathering lines have limited jurisdiction by the Office of Pipeline Safety. Additional information regarding jurisdiction can be found in §192.8.)*	192.3
Gathering line - type A (gas)	Metallic pipe operating at a hoop stress of 20% or more of SMYS, and non-metallic pipe with a MAOP of more than 125 psig, and is located in a Class 2, 3, or 4 location.	192.8
Gathering line - type B (gas)	Metallic pipe operating at a hoop stress of less than 20% SMYS, and non-metallic pipe with a MAOP of 125 psig, or less, and is located in a Class 3 or 4 location, or an area within a Class 2 location as determined by one of the methods: (a) Class 2 location, (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	192.8
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.	
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.	
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.	

Term	Definition	Definition Source
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.	
Graphitic corrosion	Deterioration of cast iron wherein the metallic constituents are selectively leached or converted to corrosion products, leaving the graphitic particles intact. (Should not be used to describe graphitization.)	NACE/ASTM G193 Corrosion Terms
Graphitization	The formation of graphite in iron or steel, usually from decomposition of iron carbide at elevated temperatures. *(Should not be used to describe graphitic corrosion.)*	NACE/ASTM G193 Corrosion Terms
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 leak	A leak that represents an existing or probably hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.	192.1001
High consequence area (HCA) - Gas	An area defined by certain class locations or a Potential Impact Radius that must be covered by an operator’s gas Integrity Management Program. See 49 CFR 192.903 for a complete definition	
High pressure distribution system	A distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.	192.3
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

Term	Definition	Definition Source
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.	
Human occupancy	A building used for a purpose involving the presence of humans	Interpretation PI-77-017
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.	
Hydrocarbon (H.C.) filter	A filtering element used to separate out heavier hydrocarbons when using a combustible gas indicator (CGI). Gasoline, propane, butane and commercial solvents are examples of heavier hydrocarbons.	
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
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

Term	Definition	Definition Source
Identified site - gas	(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)- month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.	192.903
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

Term	Definition	Definition Source
Incident	(1) An event that involves a release of gas from a pipeline, or of a liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and the results in one or more of the following consequences: (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost; (iii) Unintentional estimated gas loss of three million cubic feet or more; (2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident. (3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.	191.3
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.	
Inhibitors	An additive used to retard undesirable chemical action in a pipeline or pipeline facility when added in small quantities.	
Injector type odorizer	A pump-type odorizer. The flow rate of the gas stream is monitored by an electronic sensor which, in turn, controls the odorant pump injection rate.	
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)
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

Term	Definition	Definition Source
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 plan (IM Plan)	A written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.	192.1001
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
Integrity management program (IM Program)	An overall approach by an operator to ensure the integrity of its gas distribution system.	192.1001
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
Internal corrosion direct assessment (ICDA)	Process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.	192.927(a)
Interstate gas pipeline facility	A gas pipeline facility (a) used to transport gas; and (b) subject to the jurisdiction of the Commission under the Natural Gas Act (15 U.S.C. 717 et seq.)	49 U.S.C 60101
Intrastate gas pipeline facility	A gas pipeline facility and transportation of gas within a State not subject to the jurisdiction of the Commission under the Natural Gas Act (15 U.S.C 717 et seq.).	49 U.S.C 60101
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
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.	

Term	Definition	Definition Source
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.	
Large volume customer	A customer who receives similar volumes of gas as a distribution center. This may include factories, power plants and institutional users.	192.3
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 classification	A method of classifying leaks according to their size, hazard to persons or property and required remedial actions to reduce the hazard.	
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.	
Leakage survey	A systematic inspection of a pipeline for the purpose of finding leaks on a gas piping system. Leakage surveys may be done with or without instruments, depending on the class location and type of system.	GPTC
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 line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.	192.3
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.	
Liquefied petroleum gas (LPG) air mixture	Liquefied petroleum gases distributed at relatively low pressures and normal atmospheric temperatures which have been diluted with air to produce desired heating value and utilization characteristics.	
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.	
Listed specification	A specification listed in (49 CFR 192) Section I of Appendix B of 192.	192.3

Term	**Definition**	**Definition Source**
Local distribution company (LDC)	A local gas company responsible for distributing gas to its customers. An LDC purchases gas from transmission companies for resale to the consumer. LDC's operate and maintain the underground piping, regulators, and meters that connect to each residential and commercial customer.	
Lock-up	The point at which a regulator shuts off completely. Lock up is important so that, under no-flow conditions, the regulator does not seep gas downstream.	
Long term hydrostatic strength (of plastic pipe)	The estimated hoop stress of thermoplastic pipe, in psi, which would result in a failure of the pipe if it were subjected to 100,000 hours of hydrostatic pressure.	GPTC
Lower explosive limit (LEL)	The lower limit of flammability for a gas expressed as a percent, by volume, of gas in air.	GPTC
Low-pressure distribution system	A distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.	192.3
Main	A distribution line that serves as a common source of supply for more than one service line.	192.3
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.	
Master meter	A pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents.	191.3
Maximum actual operating pressure	The maximum pressure that occurs during normal operations over a period of 1 year.	192.3
Maximum allowable hoop stress - gas	The maximum hoop stress permitted for the design of a piping system. It depends upon the material used, the class location of the pipe and the operating conditions.	
Maximum allowable operating pressure (MAOP)	Means the maximum pressure at which a pipeline or segment of a pipeline may be operated under Part 192. (*See §192.619 for further guidance.)*	192.3
Maximum allowable test pressure	The maximum internal fluid pressure permitted for testing pipe. The calculations will be dependent upon pipe materials, testing medium, intended operating pressures, class location, and proximity to buildings.	
MCF	A measurement term used to indicate one thousand cubic feet of gas.	

Term	Definition	Definition Source
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
Mercaptan	A group of organic chemical compounds having a very strong and distinctive odor used for odorization of gas streams. Since natural gas is odorless, mercaptan is added to the gas so that people can smell escaping or leaking gas.	
Meter	Any mechanical device used to measure the volume throughput of natural gas or petroleum liquids.	
Meter set assembly	The exposed portion of the service line extending from the service line riser valve to the connection of the customer's fuel line, including the meter, and (if present) the regulator and relief vent line. In the absence of a service line riser valve, the meter assembly starts at the first exposed fitting. The meter set assembly does not include the customer's buried or exposed fuel line. If the operator's service line continues past the meter and connects to the customer's fuel line at a location some distance downstream of the meter, the meter set assembly ends at the meter outlet valve (if present) or at the first exposed fitting (i.e., coupling or union) downstream of the meter.	GPTC
Methane	CH_4 is the lightest in the paraffin series of hydrocarbons. It is colorless, odorless and flammable, and forms the major portion of natural gas. It is also lighter than air and will rise if released from containment.	
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.	
MMCF	A measurement term used to indicate one million cubic feet of gas.	
Monitoring regulators	A pressure regulator set in series with another pressure regulator, for the purpose of providing automatic overpressure protection in the event of a malfunction of the primary regulator. Backup regulator systems can be assembled in a variety of arrangements. Monitoring regulators are typically set at a control pressure slightly higher than the primary regulators.	
Municipality	A city, county, or any other political subdivision of a state.	192.3
Natural gas liquids	Heavy hydrocarbons found in natural gas, which may be extracted or isolated and processed as liquefied petroleum gas (LPG) (examples include propane, butane, and natural gasoline).	
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

Term	Definition	Definition Source
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
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, in inches, computed by, or used in, the design formula for steel pipe in §192.105. Pipe may be ordered to this computed wall thickness without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications.	GPTC
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	
Odorant	A chemical substance added to natural gas so that the odor can be used as a warning sign of the presence of escaping gas. *(For additional odorant requirements, see 192.625 (c)).*	
Odorization	The process of adding an odor to natural gas. Since natural gas is odorless, odorant is added to the gas so that people can smell escaping or leaking gas and report to the gas companies for further investigation	
Odorizer	A piece of equipment that adds chemical odorant to flowing natural gas pipelines.	
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
Operating stress	The stress imposed on a pipe or structural member under normal operating conditions.	GPTC
Operator	A person who engages in the transportation of gas.	192.3
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

Term	Definition	Definition Source
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.	
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.	
Peak shaving	The process of supplying additional gas volumes to supplement the throughput supply of pipeline gas during periods of extremely high demand. The use of LNG, propane, or drawing reserves out of underground storage and pipeline vessels are methods of peak shaving.	
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.	
Petroleum gas	Propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 1434 kPa (208 psig) at 38°C (100°F).	192.3
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.	
Pinpointing	The process of locating the exact source of a gas leak along a pipeline route with a minimum of excavation. This is accomplished using a gas measuring analyzer and a non-sparking metal plunger bar to punch holes in the ground along the pipeline's right-of-way. See "centering".	
Pipe	Any pipe or tubing used in the transportation of gas, including pipe-type holders.	192.3

Term	Definition	Definition Source
Pipeline	All parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.	192.3
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 gas or in the treatment of gas during the course of transportation.	192.3
Pipe-supporting element	A pipe-supporting element consists of fixtures and structural attachments.	
Pipe-type holder	A pipe-type holder is a container or group of interconnected pipe containers installed at one location and used for the sole purpose of storing gas.	GPTC
Pitot tube	A small device that can be inserted into a pipe to measure the flow of liquid or gas. This device is composed of two tubes arranged in such a manner that will allow the measurement of both the velocity and static pressures of the flowing liquid or gas. The difference in these pressures is a function of the flow within the pipe.	APGA
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
Plastic	A material that contains one or more organic polymeric substances of high molecular weight as an essential ingredient, is solid in its finished state, and can be shaped by flow at some stage of its manufacture or processing into finished articles. The two general types of plastic are thermoplastic and thermosetting. A material which contains, as an essential ingredient, an organic substance of high molecular weight. It is solid in its finished state and, at some stage of its manufacture or processing, was shaped or molded.	GPTC
Plastic pipe joints	Locations in plastic pipe where another length of pipe has been joined to increase its length, change direction (such as an elbow) or attach another component or branch to the system. Plastic pipe joints can be adhesive joints, heat-fusion joints, or solvent cement joints.	
Plug valve	A quarter turn metal valve in which a pierced plug rotates in a tapered or cylindrical body to control flow through the valve. Plug valves are normally used in quick open or closed applications but sometimes can be used for throttling purposes. Plug valves cannot be used in piggable pipelines.	
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 meter	A mechanical, fluid-measuring device that measures flowing volumes very accurately by filling and emptying chambers of specific volume; also known as a volume meter or volumeter. The displacement of a fixed volume of fluid may be accomplished by the action of reciprocating or oscillating pistons, rotating vanes or buckets, rotating disks, tanks or other vessels that automatically fill and empty.	

Term	Definition	Definition Source
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.	
Potential impact circle	A circle of radius equal to the potential impact radius (PIR)	192.903
Potential impact radius (PIR)	The radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d \2\)), where `r' is the radius of a circular area in feet surrounding the point of failure, `p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and `d' is the nominal diameter of the pipeline in inches. Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S-2001 (Supplement to ASME B31.8; incorporated by reference, see §192.7) to calculate the impact radius formula.	192.903
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 limiting station	An apparatus which, under abnormal conditions, will act to reduce, restrict or shut off the supply of gas flowing into a transmission line, main, holder, pressure vessel or compressor station piping in order to prevent the gas pressure from exceeding a predetermined limit. While normal pressure conditions prevail, the pressure limiting station may exercise some degree of control of the flow of gas or may remain in the wide-open position. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.	GPTC
Pressure regulating station	An apparatus installed for the purpose of automatically reducing and regulating the gas pressure in the downstream transmission line, main, holder, pressure vessel or compressor station piping to which it is connected. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.	GPTC

Term	Definition	Definition Source
Pressure relief station	An apparatus installed to vent gas from a transmission line, main, holder, pressure vessel, or compressor station piping in order to prevent the gas pressure from exceeding a predetermined limit. The gas may be vented into the atmosphere or into a lower pressure gas system capable of safely receiving the gas being discharged. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.	GPTC
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 strength test. If water is used as the testing medium, it may be called a hydrotest.	
Prime mover	An engine or turbine powered by natural gas.	
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.	
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
Public highway	A main direct road or thoroughfare in an area that is open to the public. Ownership and maintenance of a particular road should have no bearing on whether the road is a highway.	Interpretation PI-78-031
Public place	A place that is generally open to all persons in a community as opposed to being restricted to specific persons. Churches, schools, and commercial buildings as well as any publicly owned right-of-way or property which is frequented by persons are considered to be public places under §192.11(a).	Interpretation 192.11 11 December 6, 1974, Interpretation 192.11 - 13, November 18, 1975
Purging	The act of replacing agas, 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).	

Term	Definition	Definition Source
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.	
Regulator station	Equipment installed for the purpose of automatically reducing and regulating the gas pressure in the downstream pipeline, main, holder, pressure vessel or compressor station piping to which it is connected. Included are piping and auxiliary devices such as valves, control instruments, control lines, the enclosure, and ventilation equipment. (see "pressure regulating station").	GPTC
Relief valve	A mechanical device designed to open automatically and release excess pressure above a preset pressure limit.	
Remediation	A repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.	192.903
Replaced service line	A gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.	192.383
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
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.	
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

Term	Definition	Definition Source
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
Self tapping tee	A tapping tee with a self contained cutter which is installed on in-service pipe for drilling a hole in the pipe.	
Service line	A distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.	192.3
Service line serving single-family residence	A gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.	192.383
Service regulator	The device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.	192.3
Service tee	A tee fitting installed to hot tap a main for the purpose of supplying gas to a new supply line or service line.	
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.	
Shut-in test	A pressure test conducted on smaller size gas distribution or service piping done at delivery pressures to check for leaks. Also called a leak test.	
Small LPG operator	An operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.	192.1001
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 cement joint	A joint made in thermoplastic (usually polyvinylchloride or PVC) piping by the use of a solvent or solvent cement, which forms a continuous bond between the mating surfaces.	GPTC
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
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

Term	Definition	Definition Source
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)(gas)	(a) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or (b) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b)	192.3
Squeeze off tool	A maintenance device used with plastic pipe that clamps down on the pipe to restrict or totally block flow and hold system pressures of gas and enable system repair. The tool consists of flat or curved surfaces with minimum radii that come together against the pipe wall. Stops, used to prevent the pipe being squeezed beyond a minimum allowable distance specified by the pipe manufacturer, are normally an integral part of the tool.	
Standard cubic foot per hour (SCFH)	A volumetric flow rate measurement representing the amount of gas moved in one hour if it were at 60°F and under atmospheric pressure at sea level of 14.7 psi. Since gas moved within pipelines is rarely at these exact conditions, all raw flow rate data must be corrected to the standard so that variations in pressure and temperature can be accounted for.	
State	Each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.	192.3
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
Stringer pass	The initial welding pass to join two pieces of pipe together. Also called root pass.	

Term	Definition	Definition Source
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.	
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)	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
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.	
Therm	A unit of measurement describing the amount of heat a material can generate. In the gas industry, a therm represents 100,000 BTU's, which is a common unit used in the sale of natural gas.	
Thermoplastic pipe	A plastic pipe that is capable of being repeatedly softened by increase of temperature and hardened by decrease of temperature. These would include Polybutylene (PB), Polyethylene (PE), and Polyvinylchloride (PVC).	GPTC
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.	
Tracer wire	Metallic wire that is buried above plastic pipe that can be used to indicate the location of the adjacent buried plastic pipe.	
Transmission line	A pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field. Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.	192.3
Transportation of gas	The gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.	192.3
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.	

Term	Definition	Definition Source
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.	
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.	
Unaccounted for gas	The difference between the total gas purchased from all sources and the total gas accounted for as sales, net interchange, and internal company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly billing lag.	
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.	
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

Term	Definition	Definition Source
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.	
Wet gas	Natural gas containing liquid, including water or liquefiable hydrocarbons such as natural gasoline, butane, pentane and other light hydrocarbons that can be removed by chilling, pressurization, or other extraction methods. For operator established tariff purposes, any gas containing water vapor in excess of 7 pounds per million cubic feet (mmcf) is considered wet gas.	
Wick-type odorizer	Equipment that odorizes the natural gas by having the natural gas flow across a wick in a pipe bottle saturated with odorant. Wick-type odorizers are generally used for odorizing individual lines such as farm taps.	
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.	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.603
Section Title	Procedural Manual – General Provisions
Existing Code Language	(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart. (b) Each operator shall keep records necessary to administer the procedures established under §192.605. (c) 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, 35 FR 13257, 08-19-1970
Last Amendment	Amdt. 192-75, 61 FR 18517, 04-26-1996
Interpretation Summaries	**Interpretation: PI-93-047 Date: 08-05-1993** Under parts 191 and 192, operators may use any recordkeeping procedure that produces authentic records, without the prior approval of this agency. Although authenticity of records concerns us – for both computer and paper records - we do not believe there is sufficient need to adopt generally applicable standards governing recordkeeping procedures. **Interpretation: PI-11-046 Date: 07-15-1993** The regulations governing the transportation of gas by pipeline are in 49 CFR Part 192. These regulations do not contain inspection requirements that apply specifically to customer meter sets. However, because customer meter sets are part of service lines, the sets are subject to the same inspection requirements as service lines. These requirements include monitoring for atmospheric corrosion under §192.481 and periodic leakage surveys under §192.723. Records of corrosion inspections are required by §192.491, and §192.603(b) requires records of leakage surveys. These records may cover pipelines as a whole, and need not identify specific parts of the pipeline, such as customer meter sets. **Interpretation: PI-11-030 Date: 01-26-1983**

	There is no current design requirement for scraper traps in the Part 192 equal to §195.124, nor is there a requirement in Part 192 comparable to §195.426. However, the operating requirements of §§192.603(b) and 192.605(a) may be applied to scraper traps. **Interpretation: PI-11-15 Date: 11-06-1974** It is not mandatory that an operator include material presented by PHMSA at industry seminars in an operating and maintenance plan under Section 192.603(b). The material is presented as a guide to operators. A single operator and maintenance plan may suffice for running all of the systems. However, any peculiarities in a system must be covered as required by Part 192 in the operator's plan, either in the single plan or in a separate plan. **Interpretation: PI-72-031 Date: 07-17-1972** Section 192.603(b) requires that each operator shall establish a written operating and maintenance plan meeting the requirements of the Federal gas safety regulations and keep records necessary to administer the plan. If an operator requires maps as a record to properly administer the operating and maintenance plan to meet the Federal safety requirements, then these maps must be maintained by the operators.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available. See also GPTC Guide Material under §192.605
Guidance Information	1. Paragraph §192.603(a) is a general compliance requirement that is used in conjunction with another specific violation within this subpart. 2. If possible, a more specific regulation within Part 192 and/or provisions within the operator's operations and maintenance procedures should be used as the primary citation with §192.603 providing additional support. 3. When a regulation does not specifically require records, then paragraph §192.603(b) can be used when appropriate records have not been kept.
Examples of a	1. Operating a segment of the pipeline system that is not in accordance with this

Probable Violation	subpart. 2. Records necessary to administer the procedures required by §192.605 are not maintained. 3. Computerized records were not managed properly, did not have adequate information to verify the inspection, records were lost, deleted or otherwise destroyed. 4. Records lack sufficient details to document the actual work performed.
Examples of Evidence	1. If missing record(s) are an issue, copies of the associated records for adjacent intervals either side of the missing record should be acquired. 2. If paper or electronic records are incomplete, copies or printouts of the incomplete records should be acquired. 3. A copy of the operator's operations and maintenance procedures associated with the required record should be acquired. 4. Document from whom, when, and where the records were requested, and that the operator was unable to provide the requested records or that the inspections were not properly recorded to be included in inspection and the violation summary. 5. The inspector may want to issue a Request for Specific Information (RFSI) to further document the records request and the missing records if the operator fails to provide an appropriate response.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.605(a)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies - General
Existing Code Language	(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-71, 59 FR 6584, 02-11-1994 (affecting 192.605(a))
Interpretation Summaries	**Interpretation: PI-ZZ-055 Date: 12-24-2002** OPS is aware of the industry practice known as "soft closure" under which an operator continues to provide gas service to a property during the interval between termination of one customer's account and initiation of the successor's account. An operator must determine on a site-specific basis what actions are consistent with the requirement to remove from service any segment of pipeline that becomes unsafe. Various actions are possible to reduce risks and these should be incorporated *in* the procedural manual required by §192.605 **Interpretation: PI-94-034 Date: 10-24-1994** Operators must include in their manuals as much design and construction information, such as welding or other joining procedures, as is necessary to carry out operation, maintenance, and emergency response activities. For example, if a pipeline is to be repaired by replacing a segment of pipe, the operator's O&M manual would have to have design and construction information appropriate for that type of repair. Also, the O&M manual must contain procedures that enable operating and maintenance personnel to obtain as much original design and construction information as they need to carry out their assignments. However, such original information may be maintained apart from the manual. **Interpretation: PI-ZZ-045 Date: 05-26-1993**

An operation and maintenance plan must cover meter turn-on operations. However, it is §192.605(a), not §192.605(b), that requires inclusion of the operations within the plan.

Interpretation: PI-ZZ-043 Date: 05-17-1993

OSHA regulations in 29 CFR§§1926.651(g)(1)(iii) and 1926.651(g)(2)(i) are preempted by PHMSA pipeline standards.

Interpretation: PI-93-019 Date: 04-28-1993

Regulator stations must be inspected and tested to comply with §192.739 using any practicable method that will demonstrate the presence or absence of the listed qualities. Set-point, lock-up, and full-stroke-operation would be part of the inspection and testing if such tests are practicable at the station concerned. If not, whatever other tests are practicable in meeting the requirements of §192.739 must be saved. Specific procedures should be documented in the utility's operating and maintenance plan prescribed by §192.605.

Interpretation: PI-ZZ-062 Date: 07-25-1990

We consider cutting off of gas service at the meter, regardless of the purpose, to be a normal operation or maintenance function covered by the operating and maintenance plan requirements of §§192.603 and 192.605. Any function an operator includes in this plan, including functions that are not otherwise regulated by Part 192, is a regulated function because compliance with the plan is mandatory. Thus, performance of any function described in an operator's plan that is intended to implement §§192.603 and 192.605, including the temporary cutting off of gas service at the meter, would make the person who performs the function subject to drug testing under Part 199.

Interpretation: PI-ZZ-030 Date: 01-26-1983

There is no current design requirement for scraper traps in the Part 192 equal to §195.124, nor is there a requirement in Part 192 comparable to §195.426. However, the operating requirements of §§192.603(b) and 192.605(a) may be applied to scraper traps.

Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-10-06, Personal Electronic Device (PED) Related Distractions.** As with other modes of transportation, PHMSA recognizes the use of PEDs by pipeline employees who are performing operations and maintenance activities may increase safety risks if those individuals become distracted. In furtherance of the Department's effort to end the dangerous practice of distractions caused by PEDs throughout the various modes of transportation, PHMSA is issuing this Advisory Bulletin about the potential for distractions affecting pipeline safety. PHMSA reminds owners and operators of natural gas and hazardous liquid pipeline facilities that there may be increased risks associated with the use of PEDs by individuals performing activities that affect pipeline operation or integrity. Pipeline operations and maintenance tasks require a critical level of attention and skill, which may be compromised by visual, manual, and cognitive distractions caused by the use of PEDs. Such distractions may also hinder their prompt recognition and reaction to abnormal operating conditions and emergencies. Owners and operators of natural gas and hazardous liquid pipeline facilities should integrate into their written procedures for operations and maintenance appropriate controls regarding the personal use of PEDs by individuals performing pipeline tasks that may affect the operation or integrity of a pipeline. PHMSA is not discouraging the use of PEDs as a part of normal business operations. Owners and operators should also provide guidance and training for all personnel about the risks associated with the use of PEDs while driving and while performing activities on behalf of the company if that use poses a risk to safety. **Advisory Bulletin ADB-08-04, Installation of Excess Flow Valves into Gas Service Lines** The Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act of 2006 (Pub. L. 109-468) mandates that PHMSA require operators of natural gas distribution systems to install excess flow valves (EFV) on certain gas service lines. The statute directs that installation of EFVs will be required on single family residence service lines: • That are installed or entirely replaced after June 1, 2008; • That operate continuously throughout the year at a pressure not less than 10 psi gauge; • That are not connected to a gas stream with respect to which the operator has had prior experience with contaminants the presence of which could interfere with the operation of an EFV, and • For which an excess flow valve meeting the performance standards of 49 CFR 192.381 is commercially available. **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 Excavation 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-02-03, Gas and Hazardous Liquid Pipeline Mapping.

This bulletin is issued 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.

Advisory Bulletin ADB-01-02, Emergency Plans and Procedures for Responding to Multiple Gas Leaks and Migration of Gas Into Buildings.

Owners and operators of gas distribution systems should ensure that their emergency plans and procedures require employees who respond to gas leaks to consider the possibility of multiple leaks, to check for gas accumulation in nearby buildings, and, if necessary, to take steps to promptly stop the flow of gas. These procedures should be communicated to both employee and contractor personnel who are responsible for emergency response to pipeline incidents.

Advisory Bulletin ADB-01-01, Closure of Gas Shut-Off Valves Serving Permanently Moored Vessels (PMV) During High-Water Conditions.

The Office of Pipeline Safety (OPS) is issuing this advisory to gas distribution pipeline system operators. Operators should examine the shut-off valves controlling gas service to permanently moored vessels (PMV) and ensure that gas service can be quickly shut down, if necessary, even during high-water conditions. In addition, operators should review their operations and maintenance manual and their emergency response manual to ensure that procedures are in place to successfully shut down the flow of gas to PMVs when necessary, including during high-water conditions.

	Advisory Bulletin ADB-99-04, Directional Drilling and Other Trenchless Technology Operations Conducted in Proximity to Underground Pipeline Facilities. This bulletin advises owners and operators of natural gas and hazardous liquid pipeline systems to review, and amend if necessary, their written damage prevention program to minimize the risks associated with directional drilling and other trenchless technology operations. **Advisory Bulletin ADB-99-03, Potential Service Interruptions in Supervisory Control and Data Acquisition Systems.** This bulletin advises pipeline system owners and operators of the potential operations limitations associated with SCADA systems and the possibility of those problems leading to or aggravating pipeline releases.
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. The operator must have written procedures addressing each requirement of §192.605. At a minimum the procedures must include coverage of maintenance, normal operations, abnormal operations, safety-related conditions, and emergency conditions. 2. An operator's operations and maintenance procedures manual may vary in length and complexity depending on the specific equipment in service, the variety of facilities, the locations, and referenced versus incorporated material. The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. 3. The structure of the operations and maintenance procedures manual is not prescribed and may consist of a single comprehensive manual or multiple cross-reference volumes with referenced documents. The manuals can be made available to operations personnel as hard-copy or computer based documents but must be accessible at locations where operations and maintenance activities are conducted. If the operations and procedures manual(s) are computer based, the operator must provide a means to access the procedures in the event of computer failure. 4. Procedures that are unique to a particular facility must be accessible at that facility. 5. Purchased or off-the-shelf O&M procedures must be fully customized to the operator to cover their specific operating requirements. 6. In addition to operations and maintenance functions performed by field personnel, tasks performed by operations control, engineering, integrity management and other functions associated with an office facility require written procedures that must be included in the operations and maintenance manual.

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7. The operations and maintenance procedures must be specific to address the facilities and equipment being used by the operator. The regulations define the minimum requirements but an operator's procedures may need to exceed these basic requirements to ensure safe operation of the pipeline system. The operator's written operations and maintenance procedures are enforced as a regulation.
8. The operator must review and update, if necessary, the operations and maintenance procedures at least once each calendar year not to exceed 15 months. The operator must show that normal operations, abnormal operations, incidents, and emergency conditions were reviewed to determine if procedures modifications are needed. The individual procedures documents should include management approvals, origin date, and the effective date of the last revision.
9. Final Order Guidance:
    a. **Williams Gas Pipeline [1-2005-1007] (July 30, 2007):** 49 C.F.R. §192.605(a) requires that operators "prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response." Pursuant to this regulatory requirement, when operators' own written procedures require its inspectors to assist the construction contractor in verifying the staked location of the Company's existing facilities," failure to comply is a violation of the regulatory mandate. Operators are required "to aid or assist the construction contractor in any meaningful way to verify the location of the company's facilities." CO/CP

    b. **Williams Gas Pipeline [5-2009-1003] (October 14, 2010):** Operator violated 49 C.F.R. §192.605(a) by failing to follow its own procedures, which prohibited using composite sleeves to repair leaks, cracks, or weld imperfections. CO/CP

    c. **Northern Natural Gas Company [3-2003-1009] (February 16, 2006):** 49 C.F.R. §192.613(a) requires operators "to establish procedures for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location." If operators follow their own procedures, but are still unable to take appropriate action, regulatory compliance pursuant to §192.605(a) has not been achieved, as the operator must "adequately conduct continuing surveillance of its facilities in accordance with the operating procedures established under §192.613(a). CP

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Examples of a Probable Violation

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1. The operator does not have a procedure that covers the tasks being performed.
2. The operator fails to follow the written procedures.
3. The written procedures have not been reviewed and/or updated within the required intervals.

4. The operator has employed new equipment or technologies without having the appropriate procedures.
5. The operator fails to provide proper training on the operations and maintenance procedures required by §192.605.
6. All written versions of the O&M Manual are not current and up to date.

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Examples of Evidence	1. Copies of the written procedures in question. 2. Copies of the operator's records indicating that the procedures were not followed. 3. A written record of the observed actions that violated the procedures. 4. Photographs showing the probable violation. 5. Documented statements made by representatives of the operator pertaining to missing or inadequate procedures. 6. If paper or electronic records are incomplete, copies or printouts of the incomplete records should be acquired. 7. Written documentation of conversations or interviews with the operator's personnel. 8. Incident investigation reports that document failure to follow procedures or problems with the procedures. 9. Copies of training records with no documentation of specific training on the operations and maintenance procedures.
Other Special Notations	1. If inadequacies are found with the written procedures, the inspector should prepare a Notice of Amendment.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.605(b)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies - Maintenance and Normal Operations
Existing Code Language	(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations. (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part. (2) Controlling corrosion in accordance with the operations and maintenance requirements of Subpart I of this part. (3) Making construction records, maps, and operating history available to appropriate operating personnel. (4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner. (5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices. (6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service. (7) Starting, operating and shutting down gas compressor units. (8) Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedure when deficiencies are found. (9) 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. (10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including - (i) Provision for detecting external corrosion before the strength of the container has been impaired; (ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and, (iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity. (11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under §192.615(a)(3) specifically apply to these reports. (12) Implementing the applicable control room management procedures required by §192.631.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970

Last Amendment	Amdt. 192-112, 74 FR 63310, 12-03-2009
Interpretation Summaries	**Interpretation: PI-94-034 Date: 10-24-1994** Operators must include in their manuals as much design and construction information, such as welding or other joining procedures, as is necessary to carry out operation, maintenance, and emergency response activities. For example, if a pipeline is to be repaired by replacing a segment of pipe, the operator's O&M manual would have to have design and construction information appropriate for that type of repair. Also, the O&M manual must contain procedures that enable operating and maintenance personnel to obtain as much original design and construction information as they need to carry out their assignments. However, such original information may be maintained apart from the manual.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-10-06, Personal Electronic Device (PED) Related Distractions.** As with other modes of transportation, PHMSA recognizes the use of PEDs by pipeline employees who are performing operations and maintenance activities may increase safety risks if those individuals become distracted. In furtherance of the Department's effort to end the dangerous practice of distractions caused by PEDs throughout the various modes of transportation, PHMSA is issuing this Advisory Bulletin about the potential for distractions affecting pipeline safety. PHMSA reminds owners and operators of natural gas and hazardous liquid pipeline facilities that there may be increased risks associated with the use of PEDs by individuals performing activities that affect pipeline operation or integrity. Pipeline operations and maintenance tasks require a critical level of attention and skill, which may be compromised by visual, manual, and cognitive distractions caused by the use of PEDs. Such distractions may also hinder their prompt recognition and reaction to abnormal operating conditions and emergencies. Owners and operators of natural gas and hazardous liquid pipeline facilities should integrate into their written procedures for operations and maintenance appropriate controls regarding the personal use of PEDs by individuals performing pipeline tasks that may affect the operation or integrity of a pipeline. PHMSA is not discouraging the use of PEDs as a part of normal business operations. Owners and operators should also provide guidance and training for all personnel about the risks associated with the use of PEDs while driving and while performing activities on behalf of the company if that use poses a risk to safety. **Advisory Bulletin ADB-02-03, Gas and Hazardous Liquid Pipeline Mapping.**

	This bulletin is issued 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. **Advisory Bulletin ADB-00-02, Internal Corrosion in Gas Transmission Pipelines.** This bulletin is issued to owners and operators of natural gas transmission pipeline systems to advise them to review their internal corrosion monitoring programs and operations. Operators should consider factors that influence the formation of internal corrosion, including gas quality and operating parameters. Operators should give special attention to pipeline alignment features that may contribute to internal corrosion by allowing condensates to settle out of the gas stream.
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. The operator must have written procedures addressing each requirement of §192.605. 2. An operator's operations and maintenance procedures manual may vary in length and complexity depending on the specific equipment in service, the variety of facilities, the locations, and referenced versus incorporated material. The procedures must be detailed to clearly describe the manner in which each requirement will be met. 3. The structure of the operations and maintenance procedures manual is not prescribed and may consist of a single comprehensive manual or multiple cross-reference volumes with referenced documents. The manuals can be made available to operations personnel as hard-copy or computer based documents but must be accessible at locations where operations and maintenance activities are conducted. If the operations and procedures manual(s) are computer based, the operator must provide a means to access the procedures in the event of computer failure. 4. Procedures that are unique to a particular facility must be accessible at that facility. 5. In addition to operations and maintenance functions performed by field personnel, tasks performed by operations control, engineering, integrity management and other functions associated with an office facility require written procedures that must be included in the operations and maintenance manual. 6. The operations and maintenance procedures must be specific to address the facilities and equipment being used by the operator. The regulations define the minimum requirements but an operator's procedures may need to exceed these

	basic requirements to ensure safe operation of the pipeline system. The operator's written operation and maintenance procedures are enforced as a regulation. 7. The procedures should be clear, straightforward and applicable to the company's system. 8. The operator must review and update, if necessary, the operations and maintenance procedures at least once each calendar year not to exceed 15 months. The operator must show that normal operations, abnormal operations, incidents, and emergency conditions were reviewed to determine if procedures modifications are needed. The individual procedures documents should include management approvals, origin date, and the effective date of the last revision. 9. More specific than the requirements addressed in §192.605(a), as noted above. 10. Personnel conducting pipeline operations need direct access (either on paper or electronically) to procedures, without delay when emergencies arise. 11. §192.605(b) (8) is directed to procedures refinement, not employee evaluation. 12. 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 incident data, near miss data, 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 management of change management process should show the procedure modification that was made in response to the analysis. 13. Observation of operator qualification training, where an operation or maintenance task is performed, is not by itself adequate to satisfy the requirements of §192.605(b)(8). 14. Refinement and efficiency of procedures must not compromise safety. 15. It is acceptable for operators to use the manufacturer's recommended maintenance practices for compressor station maintenance (engine books, maintenance bulletins, etc.) regarding the applicable equipment at each location. If used, documents must be available at the work location (manuals at the office responsible for the work is acceptable). 16. It is acceptable to post the specific start-up and shut-down instructions for each compressor unit at or near the local control panel used for operating the equipment; and have generic guidance procedures in its O&M Plan. 17. Isolation and ESD procedures must be specific for each location. 18. Properly structured procedure manuals will allow personnel to easily find specific O&M procedures. 19. Operators must be able to provide a list of manuals that represent the entire set of required procedures. 20. 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. 21. The OPS procedures required to protect employees from vapors in excavations is different than OSHA confined space procedures. 22. Final Order Guidance: a. **El Paso Corporation [5-2008-1005] (November 23, 2009):** 49 C.F.R. §192.605(b)(3) requires that an operator make available "construction

	records, maps, and operating history . . .to appropriate operating personnel." In order to achieve compliance, operators must make this information "ready for use; at hand; and accessible (PHMSA Advisory Bulletin ADB-02-03)." In situations where personnel have to travel several miles to retrieve accurate or thorough information, "meaningful compliance with the regulatory requirement" has not been achieved. CO/CP
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks being performed. 2. The operator fails to follow the written procedures. 3. The written procedures have not been reviewed and/or updated within the required intervals. 4. The operator has employed new equipment or technologies without having the appropriate procedures. 5. The operator's procedures for taking adequate precautions in excavated trenches do not include the use of appropriate instruments to test the atmosphere in the trench. 6. The only procedures for addressing vapors in excavated trenches are OSHA's confined space procedures.
Examples of Evidence	1. Copies of the written procedures in question. 2. Copies of the operators required records indicating that the procedures were not followed. 3. A written record of the observed actions that violated the procedures. 4. Photographs showing the probable violation. 5. Written documentation of conversations with the operator's personnel who are charged with establishing and following the plan. 6. The operator's internal incident investigation documents and PHMSA 7100.2 incident reports.
Other Special Notations	1. If inadequacies are found with the written procedures the inspector should prepare a Notice of Amendment.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.605(c)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies – Abnormal Operation
Existing Code Language	(c) Abnormal operation. For transmission lines, 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; 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. (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) Notifying responsible operator personnel when notice of an abnormal operation is received. (4) 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. (5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connections with their distribution system.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-71A, 60 FR 14381, 03-17-1995 (Affecting 192.605(c))
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-99-03, Potential Service Interruptions in Supervisory Control and Data Acquisition Systems.** Inform pipeline system owners and operators of potential operational limitations associated with Supervisory Control and Data Acquisition (SCADA) systems and the possibility of those problems leading to or aggravating pipeline releases. 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	GPTC Guide Material is available
Guidance Information	1. The operator's operations and maintenance procedures must address abnormal operations as defined by §192.605(c). Abnormal operations and emergency response are not the same, and the operator must have separate procedures to address each type. However, failure by the operator to make an appropriate, timely response to an abnormal operation could result in an emergency situation. 2. The structure of the operations and maintenance procedures manual is not prescribed and may consist of a single comprehensive manual or multiple cross-reference volumes with referenced documents. The manuals can be made available to operations personnel as hard-copy or computer based documents but must be accessible at locations where operations and maintenance activities are conducted. If the operations and procedures manual(s) are computer based, the operator must provide a means to access the procedures in the event of computer failure. 3. The operator's operations and maintenance procedures must adequately address each type of abnormal operation defined by §192.605(c) and clearly provide the appropriate response based on the situation and facilities involved. 4. Procedures that are unique to a particular facility must be accessible at that facility. 5. In addition to operations and maintenance functions performed by field personnel, tasks performed by operations control, engineering, integrity management and other functions associated with an office facility require written procedures for abnormal operations that must be included in the operations and maintenance manual. 6. The operator's procedures must specify the documentation requirements for abnormal operations events. Recording only those abnormal operations that result in a Part 191 reportable incident is not adequate. Abnormal operations must be documented 7. 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 8. Procedures revisions made to increase efficiency must not compromise safety. 9. The operations and maintenance procedures must be specific to address the

	facilities and equipment being used by the operator. The regulations define the minimum requirements but an operator's procedures may need to exceed these basic requirements to ensure safe operation of the pipeline system. The operator's written operations and maintenance procedures are enforced as a regulation. 10. The operator must review and update, if necessary, the operations and maintenance procedures at least once each calendar year not to exceed 15 months. The operator must show that normal operations, abnormal operations, incidents, and emergency conditions were reviewed to determine if procedure modifications are needed. The individual procedures documents should include management approvals, origin date, and the effective date of the last revision. 11. The operator's operations and maintenance procedures must specify how checking for variations after returning to normal operations after an abnormal operations event has occurred will be performed. This checking must be performed in a manner to ensure continued integrity and safe operation. 12. The operator's operations and maintenance procedures for abnormal operations must include a process to evaluate the effectiveness and include defined actions where the procedures are found to have deficiencies. The operator must be able to show documentation that this review is being performed and the results of the review. The procedures modifications must reflect revisions to correct any deficiencies determined in the review process. The operator can use a variety of methods to determine the effectiveness of the procedures, including root cause analysis, post-event reports, discussions in safety meetings, evaluation of close-call reports, and table-top or live drills. Refinement of the procedures to improve efficiency must not compromise safety.
Examples of Probable Violation	1. The operator failed to prepare and follow procedures for abnormal operations. 2. The operator failed to document occurrences of abnormal operations. 3. The operator failed to review the abnormal operations procedures and correct any deficiencies. 4. The operator has not prepared and followed procedures for monitoring conditions after an abnormal operation event to ensure continued integrity and safe operation.
Examples of Evidence	1. Copies of the written procedures in question. 2. Copies of the operators required records indicating that the procedures were not followed. 3. A written record of the observed actions that violated the procedures. 4. Written documentation of conversations or interviews with the operator's personnel. 5. Incident investigation reports that document failure to follow procedures or problems with the procedures. 6. The operations control log book that for the time period surrounding the abnormal operating event that does not clearly show a response according to the defined procedures. 7. Data from the SCADA system or the operations control log book that fails to detail monitoring after an abnormal operating event to ensure continued integrity

	and safe operation. 8. Data from the SCADA system that shows system operating parameters during the period of the abnormal operation.
Other Special Notations	1. If inadequacies are found with the written procedures the inspector should prepare a Notice of Amendment.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.605(d)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies – Safety-related Condition Reports
Existing Code Language	(d) 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 §191.23 of this sub-chapter.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970.
Last Amendment	Amdt. 192-71, 59 FR 6584, 02-11-1994 (Affecting 192.605(d))
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available §191.23 Reporting safety-related conditions. (a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §191.25 the existence of any of the following safety-related conditions involving facilities in service: (1) In the case of the pipeline (other than an LNG Facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, 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 the serviceability of a pipeline or the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG. (3) Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains controls, or processes gas or LNG. (4) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength. (5) Any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-

	up allowed for operation of pressure limiting or control devices. (6) A leak in a pipeline or LNG Facility that contains or processes gas or LNG that constitutes an emergency. (7) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank. (8) 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 or an LNG Facility that contains or processes gas or LNG. (b) A report is not required for any safety-related condition that- (1) Exists on a master meter system or a customer-owned service line; (2) Is an incident or results in an incident before the deadline for filing the safety-related condition report; (3) Exists on a pipeline (other than an LNG facility) 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 (4) 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. §191.25 Filing safety-related condition reports. (a) Each report of a safety-related condition under §191.23(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's operations and maintenance procedures must address safety-related condition reports as defined by §192.605(c). 2. An operator's operations and maintenance procedures manual may vary in length and complexity depending on the specific equipment in service, the variety of facilities, the locations, and referenced versus incorporated material. The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. 3. The structure of the operations and maintenance procedures manual is not prescribed and may consist of a single comprehensive manual or multiple cross-reference volumes with referenced documents. The manuals can be made available to operations personnel as hard-copy or computer based documents but must be accessible at locations where operations and maintenance activities are conducted. If the operations and procedures manual(s) are computer based, the operator must provide a means to access the procedures in the event of computer failure. 4. Procedures that are unique to a particular facility must be accessible at that facility. 5. The operator's procedures must specify the appropriate personnel to recognize and appropriately respond to safety-related conditions. These include, but are not limited to, operations, maintenance, operations control, engineering, corrosion, and integrity management personnel. The procedures must include parameters to recognize the condition, initiate the proper response, determine the proper operating pressure reduction, and make the proper repairs within the prescribed time period. 6. The operator's procedures should address the occurrence and proper response for a safety related condition within a High Consequence Area (HCA) as well as outside of a HCA. The operators' procedures should delineate the differences between discovery and determination.
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks being performed. 2. The operator fails to follow the written procedures. 3. The written procedures have not been reviewed and/or updated within the required intervals. 4. The operator fails to provide proper training on the operations and maintenance procedures required by §192.605. 5. Failure to report a pressure reduction in an HCA as a SRC.
Examples of Evidence	1. Copies of the written procedures in question. 2. Copies of the required operator records indicating that the procedures were not followed. 3. A written record of the observed actions that violated the procedures. 4. Photographs showing the probable violation. 5. Written documentation of conversations or interviews with the operator's personnel.

	6. Incident investigation reports that document failure to follow procedures or problems with the procedures. 7. Copies of training records with no documentation of specific training on the operations and maintenance procedures.
Other Special Notations	1. If the written procedures are found to be inadequate, the inspector should prepare a Notice of Amendment. 2. Procedures concerning new regulations that were placed in force after the PHMSA team operations and maintenance procedures inspection and those known to have changed since the team inspection should be reviewed.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.605(e)
Section Title	Procedural Manual for Operations, Maintenance, and Emergencies – Surveillance, Emergency Response, and Accident Investigation
Existing Code Language	(e) Surveillance, emergency response, and accident investigation. The procedures required by §§ 192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.
Origin of Code	Original Code Document, 59 FR 6579, 02-11-1994
Last Amendment	Amdt. 192-71, 59 FR 6584, 02-11-1994
Interpretation Summaries	
Other Reference Material & Source	**Advisory Bulletin ADB-10-08, Emergency Preparedness Communications** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities that they must make their pipeline emergency response plans available to local emergency response officials. PHMSA recommends that operators provide their emergency response plans to officials through their required liaison and public awareness activities. PHMSA intends to evaluate the extent to which operators have provided their emergency plans to local emergency officials when PHMSA performs future inspections for compliance with liaison and public awareness code requirements. **Advisory Bulletin ADB-02-03, Gas and Hazardous Liquid Pipeline Mapping.** This bulletin is issued 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. **Advisory Bulletin ADB-01-02, Emergency Plans and Procedures for Responding to Multiple Gas Leaks and Migration of Gas Into Buildings.** Owners and operators of gas distribution systems should ensure that their emergency plans and procedures require employees who respond to gas leaks to consider the possibility of multiple leaks, to check for gas accumulation in nearby buildings, and, if necessary, to take steps to promptly stop the flow of gas. These procedures should be communicated to both employee and contractor personnel who are responsible

	for emergency response to pipeline incidents.
Other Reference Material & Source	GPTC Guide Material is available
Guidance Information	1. An operator's operations and maintenance procedures manual may vary in length and complexity depending on the specific equipment in service, the variety of facilities, the locations, and referenced versus incorporated material. The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. 2. The structure of the operations and maintenance procedures manual is not prescribed and may consist of a single comprehensive manual or multiple cross-reference volumes with referenced documents. The manuals can be made available to operations personnel as hard-copy or computer based documents but must be accessible at locations where operations and maintenance activities are conducted. If the operations and procedures manual(s) are computer based, the operator must provide a means to access the procedures in the event of computer failure. 3. Procedures that are unique to a particular facility must be accessible at that facility. 4. In addition to operations and maintenance functions performed by field personnel, tasks performed by operations control, engineering, integrity management and other functions associated with an office facility require written procedures that must be included in the operations and maintenance manual. 5. The operations and maintenance procedures must be specific to address the facilities and equipment being used by the operator. The regulations define the minimum requirements but an operator's procedures may need to exceed these basic requirements to ensure safe operation of the pipeline system. The operator's written operations and maintenance procedures are enforced as a regulation. 6. The operator must review and update, if necessary, the operations and maintenance procedures at least once each calendar year not to exceed 15 months. The operator must show that emergency plans, and continuing surveillance and failure investigations procedures were reviewed to determine if procedures modifications are needed. The individual procedures documents should include management approvals, origin date, and the effective date of the last revision.
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks being performed. 2. The operator fails to follow the written procedures. 3. The written procedures have not been reviewed and/or updated within the required intervals. 4. The operator has employed new equipment or technologies without having the appropriate procedures. 5. The operator fails to provide proper training on the operations and maintenance procedures required by §192.605.

Examples of Evidence	1. Copies of the written procedures in question. 2. Copies of the required operator records indicating that the procedures were not followed. 3. A written record of the observed actions that violated the procedures. 4. Photographs showing the probable violation. 5. Written statements by the operator's personnel. 6. Written documentation of conversations or interviews with the operator's personnel. 7. Incident investigation reports that document failure to follow procedures or problems with the procedures. 8. Copies of training records with no documentation of specific training on the operations and maintenance procedures.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.609
Section Title	Change in Class Location: Required Study
Existing Code Language	Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine: (a) The present class location for the segment involved. (b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part. (c) The physical condition of the segment to the extent it can be ascertained from available records; (d) The operating and maintenance history of the segment; (e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and, (f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	
Interpretation Summaries	**Interpretation: PI-75-009 Date: 03-07-1975** The Federal safety standards do not prohibit the transportation of gas in high pressure pipelines in subdivisions or under houses. The safety standards are written to vary in stringency depending on the proximity of a pipeline to populated areas. Also note that in the case of significant population changes surrounding certain gas pipelines, Sections 192.609 and 192.611 require pipeline operators to take specific remedial actions if necessary under the circumstances.
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	
Guidance Information	1. Refer to §192.5 and the operator's procedures for class location determination (§192.609(a)). 2. The comparison that is required of §192.609(b) must address the applicable Part 192 requirements for the present class location. For example, if a pipeline segment is to be replaced as a result of a class change, then the replacement pipe segment must comply with all of the applicable Part 192 regulations for new pipe in the present class location, §192.13(b). 3. The determination of the class location must be made using the sliding mile. 4. The operator must produce documentation that shows the current class location is commensurate with any increases in population along the pipeline route. 5. Verify that maintenance requirements are changed upon discovery to the appropriate frequencies required for the new actual class. 6. Verify the frequency of population density surveys. The class location changes when the actual change occurs, and not at the point where it is identified from a population density survey. 7. Population density surveys may be triggered by Subpart O (IM) requirements.
Examples of a Probable Violation	1. The operator cannot demonstrate that the required study included, or adequately addressed, the requirements of §192.609. 2. The operator did not properly determine the class location. 3. The operator has not performed a study to determine the change of class location when changes to the population density have occurred along the pipeline route. 4. Operator did not make appropriate changes to O&M frequencies upon discovery of class change.
Examples of Evidence	1. The documents making up the class location study. 2. Maps showing increased population density inconsistent with the operator's class determination. 3. O&M records that do not show the appropriate class frequency of patrols or leak surveys. 4. Engineering drawings (as-built, approved for construction, plans, etc.). 5. Class location/change procedures. 6. Class location/change records. 7. Patrol records. 8. MAOP verification records (pressure tests, MP5 records, pipe specs, design, installation, etc.). 9. Operating records (pressure charts/data, operating scenarios, etc.). 10. Maintenance records (leak history, inspection reports, tests, smart pig data, cathodic protection, repair records, etc.). 11. Observations, documentation (including photos). 12. Operator statements.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.611
Section Title	Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure
Existing Code Language	(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements: (1) If the segment involved has been previously tested in place for a period of not less than 8 hours: (i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations. (ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations (2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location. (3) The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria: (i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations. (ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations. (iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations (b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure

	established before the confirmation or revision. (c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§192.553 and 192.555. (d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-107, 73 FR 62177, 10-17-2008
Interpretation Summaries	**Interpretation: PI-94-019 Date: 05-02-1994** Concerning the maximum allowable operating pressure (MAOP) of pipelines in two distribution systems. Answers to questions regarding each system follow: The first system has an MAOP of 125 psig based on a maximum safe pressure (§§192.619(b)(6) and 192.621(a)(5)), but the system was operated at 145 psig during the 5-year period prior to July 1, 1970. Section 192.619(c) would allow a new MAOP of 145 psig if the system is now in "satisfactory condition," and the limitations on MAOP under §192.611 (class location change) and §192.621 (high-pressure distribution systems) are met. However, any increase in MAOP above 125 psig must comply with the uprating requirements of Subpart K of Part 192 (§192.551). Subpart K would still have to be met even if the system had been tested after construction to at least 218 psig (1.5 times 145 psig). The second system has an MAOP of 5 psig based on a maximum safe pressure, but the system was operated at 10 psig during the 5-year period prior to July 1, 1970. Although the system has been checked for corrosion and rid of leaks, the operator may not raise the MAOP to 10 psig merely by certifying that 10 psig should have been the original MAOP. As with the first system, the operator must uprate the system under Subpart K. **Interpretation: PI-89-018 Date: 09-15-1989** Responding to your belief that §192.611(a)(1) should be applicable to a pipeline where, because of a previous class location change, §192.611(a)(2) had been applied and the MAOP reduced. You included as an example data on a pipeline for which the MAOP had been reduced in 1986 from 833 psig to 675 psig. Current application of §192.611(a)(1) as amended would permit operation of the pipeline at 801 psig, which, although less than the original MAOP, is considerably higher than the current MAOP. A previous revision to §192.611 was made in 1986 (51 FR 34987, October 1, 1986, Amdt. 192-53), clarifying that the three MAOP restrictions in this section are

options. Prior to that rulemaking, many persons had assumed that the restrictions now designated (a)(1), (2), and (3) were intended to be applied sequentially as circumstances dictated. The most recent revision of this section relies heavily on this interpretation that the restrictions are options.

In the Notice of Proposed Rulemaking preceding the 1986 revision (51 FR 1978, June 3, 1986), we stated that, "RSPA does not believe that the 18-month rule blocks operators who choose one compliance option from later selecting the other." This language seems to apply in the situation described. The fundamental difference here is that in the intervening time the available compliance options have been changed. This factor, though, should not override the principle established in the previous rulemaking action, that selection and implementation of one option, e.g., lowering pressure, do not preclude later implementation of another option, e.g., retesting.

Thus, OPS believes it reasonable to interpret §192.611 to permit an operator who has previously reduced the pressure on a pipeline in response to a class location change to revisit that pipeline and raise the operating pressure within the limits now specified in §192.611(a)(1).

Interpretation: PI-82-019 Date: 10-07-1982

(1) An MAOP equivalent to 72% of SMYS may be confirmed for a new Class 2 location; (2) A preexisting MAOP must be reduced to provide a hoop stress that is not more than that allowed for new pipe in the new class location; and (3) If the operator tests to 90% of SMYS, an MAOP of 72% of SMYS may be confirmed.

Interpretation: PI-77-026 Date: 11-14-1977

If a building, constructed over an existing gas line, changes the Class location of the pipeline then the operator would have to confirm or revise the maximum allowable operating pressure in accordance with the new Class location.

Interpretation: PI-75-052 Date: 10-23-1975

Construction of a building over the pipeline may result in a change in the class location of the pipeline or the pipeline's being generally unsafe. In that event, the operator must take remedial action required by Sections 192.611, 192.613, or 192.703, as appropriate.

Interpretation: PI-ZZ-005 Date: 06-01-1972

Would construction of a bicycle path parallel to a pipeline in a Class 1 location

	require a reduction in MAOP? Answer: No **Interpretation: PI-ZZ-003 Date: 03-22-1971** Response to a developer that setting a Class location restricts future development along the pipeline. PHMSA response Class location would change and does not restrict future development. **Interpretation: PI-71-057 Date: 06-04-1971** Pipelines that are located in Class 2, 3 and 4 locations, regardless of when the segment was placed in service, cannot operate above the hoop stress that is commensurate with the present class location (ref. §192.619(a)(1)), unless the MAOP has been confirmed or revised in accordance with §192.611. §192.611 does not apply to pipelines located in Class 1 locations that operate above 72% SMYS in accordance with §192.619(c). See below for additional information. Pipelines in Class 2, 3 and 4 locations must have their operating pressures confirmed or revised in accordance with Section §192.611. However, pipelines in Class 1 locations operated at pressures which are not commensurate with that class location, based on the design stress levels of Section §192.619(a)(1), may continue to operate at their previous MAOP under the "grandfather" clause of Section §192.619(c).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available
Guidance Information	1. The 24 month time period starts when the building is suitable for human occupancy and not at the completion of the study.
Examples of a Probable Violation	1. Any MAOP confirmation or revision that is required by §192.611 that has not been completed within 24 months of a class location change. 2. Improper determination of the MAOP according to the class location. 3. Incorrect determination of class location. 4. Failure by the operator to reduce operating pressure consistent with class location. 5. Failure to perform the prescribed pressure test. 6. The confirmed or revised MAOP established under §192.611 exceeds the MAOP that existed before the confirmation or revision.

Examples of Evidence	1. Operator class location maps, data indicating building construction completion. 2. Documentation of the completion dates of new building construction not considered in the class location determination. 3. Copies of building permits, city or county records, date of utility connections, etc., that may indicate construction completion date. 4. Operator class location change records, patrol reports, class change studies, etc. 5. Pipeline segment MAOP records, segment hoop stress, test history, actual operating pressure, pressure test records, etc. 6. Operator class change procedures. 7. Operator statements pertaining to class location changes, pressure testing, and MAOP determination. 8. Field observations (photos, drawings, etc.).
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.612
Section Title	Underwater Inspection and Reburial of Pipelines in the Gulf of Mexico and its Inlets
Existing Code Language	(a) 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 effect August 10, 2005. (b) Each operator shall conduct appropriate underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from low mean 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 following year if the 6 month period is later than November 1 of the year the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation. (i) An operator may employ 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	Amdt. 192-67, 56 FR 63764, 12-05-1991
Last Amendment	Amdt. 192-98, 69 FR 48406, 08-10- 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**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 operators 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.
Other Reference Material & Source	33 CFR Part 64 MARKING OF STRUCTURES, SUNKEN VESSELS AND OTHER OBSTRUCTIONS. §191.27 – Filing off shore pipeline condition reports
Guidance Information	1. The operator must prepare and follow a procedure for inspecting pipelines that are under the requirements of this regulation. The regulation is not prescriptive as to the inspection interval and states that "periodic" inspections must be performed based on the risk of exposure or a hazard to navigation. Based on changes to the natural bottom, it is reasonable to expect an operator to perform regular, continuing, periodic inspections. It is also reasonable to expect an operator will perform underwater inspections after an event that may that may increase the risk of exposure or a result in a hazard to navigation, such as a hurricane. 2. Within 60 days, offshore condition reports must be filed as required by §191.27.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator has not identified its pipelines that are subject to the inspection requirements of this regulation. 4. The operator has not performed an inspection of its pipelines according to its procedures and the requirements of this regulation. 5. The operator fails to notify the National Response Center within the prescribed time period when it has been determined that a pipeline is exposed or poses a hazard to navigation. 6. The operator fails to mark the pipeline according to 33 CFR 64 and the requirements of this regulation within the prescribed time period. 7. The operator has not completed re-burial of the pipeline or employed engineering alternatives to protect the pipeline as required by this regulation within the prescribed time period, or failed to notify PHMSA if permits cannot be acquired in time to comply with this regulation. 8. The operator cannot provide reasonable justification that an engineering alternative meets or exceeds the level of protection provided by burial. 9. Failure to file offshore condition reports as required by §191.27 is a violation of that section of code.
Examples of	1. Documents or statements that the operator does not have procedures for

Evidence	inspecting pipelines that are subject to this part 2. A copy of the procedures should be acquired for review, if the procedures are determined to be inadequate or the operator has not followed its procedures. 3. If the operator has not identified its pipelines subject to this regulation or contends that it has no pipelines subject to the regulation, maps of the operator's pipelines in the Gulf of Mexico and along the Gulf Coast should be acquired and NPMS information should be reviewed. 4. A map or drawing of the exposed segment should be acquired and if possible, photographs of the misplaced markers or absence of markers should be taken and the coordinates documented if the operator has not properly marked its pipelines within the prescribed time period or according to the applicable regulations. 5. Operator statements that they cannot produce survey results or any type of work order for the survey. 6. Documents or statements indicating the operator has identified pipelines that must be reburied or otherwise protected according to this regulation but cannot produce documentation that the work has been completed within the prescribed time period. 7. Copies of the dated survey documents should be acquired and statements to this effect made by a representative of the operator. 8. Underwater survey results that indicate exposed pipe or pipe that may be a hazard to navigation but the operator has not taken any actions to re-bury or protect the pipe.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.613
Section Title	Continuing Surveillance
Existing Code Language	(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions. (b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved; or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).
Origin of Code	Original Code Document, 35 FR 13248, 08-19-70
Last Amendment	
Interpretation Summaries	**Interpretation: PI-89-027 Date: 12-11-1989** Regulations specify the depth to which a pipeline must be buried at the time of construction. However, when an operator learns that a pipeline is, or has become, unsafe because of potential damage of flooding or a farming activity, it must correct the problem. Remedial action may include lowering the pipeline, adding more cover over the line, or otherwise protecting it against outside force damage. **Interpretation: PI-89-023 Date: 10-18-1989** Regulations allow pipeline operators to use whatever means are suitable to achieve compliance, including aerial videotaping. We believe aerial videotaping could be an acceptable part of the process of complying with the standards, if appropriately applied by the operator. **Interpretation: PI-77-026 Date: 11-14-1977** Regarding the question whether Federal regulations contain specific requirements governing the safety of a situation where a building is proposed for construction over the area of an existing gas line. If the Class location changes the operator would have to confirm or revise the MAOP in accordance with the new Class location. Even if the Class location would not change, Section 192.613 would require that the operator take appropriate action to correct any unsafe operating conditions that might be created by construction of the building.

	Interpretation: PI-77-013 Date: 05-01-1977 Regarding whether Federal regulations would require upgrading or encasing an existing pipeline when a highway right of way is expanded, Section 192.613 requirements may apply to this situation if an unsafe condition is created b y expanding the right of way. **Interpretation: PI-77-011 Date: 04-15-1977** These regulations do not require that an existing pipeline be encased when a road is constructed over the pipeline. However, in the case of gas pipelines, Sections 192.613 and 192.703(b), and in the case of liquid pipelines, Section 195.402, require that the operator of a pipeline must take appropriate remedial action to correct an unsatisfactory condition. Applying this rule to the situation of bad construction over an existing pipeline, an operator would be obligated to correct any unsafe condition which occurs during construction of the road. The corrective action, if necessary, might include encasement or any other appropriate safety measure such as deeper burial of the line. **Interpretation: PI-77-003 Date: 01-26-1977** As initiated by loss of pipeline cover, safety standards are enforceable only against persons who own or operate pipelines and do not apply to third parties or outside contractors who may interfere with a pipeline, such as by construction of a roadway. Refusal or inability of persons other than the operator to correct unsafe situations which they have created on an operator's pipeline does not relieve the operator of its responsibility for compliance. **Interpretation: PI-75-052 Date: 10-30-1975** Construction of a building over an existing pipeline may result in an unsafe condition requiring remedial action under Section 192.613. **Interpretation: PI-75-023 Date: 05-29-1975** Construction of a road over an existing pipeline may result in an unsafe condition requiring remedial action under Section 192.613.
Advisory Bulletin/Alert	**Advisory Bulletin, ADB-11-04, Potential for damage to pipeline facilities caused by severe flooding.**

Notice Summaries	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 overflights, to evaluate right-of-way conditions at water crossings during flooding and after waters subside. Determine if flooding has exposed or undermined pipelines as a result of new river channels cut by the flooding or by erosion or scouring. 8. Perform surveys to determine the depth of cover over pipelines and the condition of any exposed pipelines, such as those crossing scour holes. Where appropriate, surveys of underwater pipe should include the use of visual inspection by divers or instrumented detection. Information gathered by these surveys should be shared with affected landowners. Agricultural agencies may help to inform farmers of the potential hazard from reduced cover over pipelines. 9. Ensure that line markers are still in place or replaced in a timely manner. Notify contractors, highway departments, and others involved in post-flood restoration activities of the presence of pipelines and the risks posed by reduced cover. If a pipeline has suffered damage, is shut-in, or is being operated at a reduced pressure as a precautionary measure as a result of flooding, the operator should

	advise the appropriate PHMSA Regional Office or State pipeline safety authority before returning the line to service, increasing its operating pressure, or otherwise changing its operating status. PHMSA or the State will review all available information and advise the operator, on a case-by-case basis, whether and to what extent a line can safely be returned to full service. **Advisory Bulletin, ADB-08-06, Dynamic riser inspection, maintenance, and monitoring records on offshore floating facilities.** To remind owners and operators of the importance of retaining inspection, maintenance, and monitoring records for dynamic risers located on offshore floating facilities. **Advisory Bulletin ADB-07-02, Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe.** All owners and operators of natural gas distribution systems who have installed and operate plastic piping are reminded of the phenomenon of brittle-like cracking. Brittle-like cracking refers to crack initiation in the pipe wall not immediately resulting in a full break followed by stable crack growth at stress levels much lower than the stress required for yielding. This results in very tight, slit-like, openings and gas leaks. Although significant cracking may occur at points of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement. Premature brittle-like cracking requires relatively high localized stress intensification that may result from geometrical discontinuities, excessive bending, improper installation of fittings, dents and/or gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the pipe failure causes fragmentation of the pipe. All owners and operators of natural gas distribution systems are further advised to review the three earlier advisory bulletins on this issue. In addition to being available in the Federal Register, these advisory bulletins are available in the docket, and on PHMSA's Web site at http://phmsa.dot.gov/ under Pipeline Safety Regulations. **Advisory Bulletin ADB-04-02, 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-99-02, Potential failures due to brittle-like cracking of older plastic pipe in Natural Gas Distribution Systems.

A review of Office of Pipeline Safety (OPS) reportable natural gas pipeline incidents and the findings of NTSB Special Investigation Report (NTSB/SIR-98/01) indicate that certain plastic pipe used in natural gas distribution service may be susceptible to brittle-like cracking. The standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.

It is recommended that all owners and operators of natural gas distribution systems identify all pre-1982 plastic pipe installations, analyze leak histories, and evaluate any conditions that may impose high stresses on the pipe. Appropriate remedial action, including replacement, should be taken to mitigate any risks to public safety.

Advisory Bulletin, ADB-99-01, Potential failure due to brittle-like cracking certain polyethylene plastic pipe manufactured by Century Utility Products Inc.

All owners and operators of natural gas distribution systems who have installed and continue to use polyethylene pipe extruded by Century Utility Products Inc, (now defunct) from the resin DHDA 2077 Tan resin manufactured by Union Carbide Corporation during the period 1970 to 1973 (Century pipe) are advised that this pipe may be susceptible to premature failure due to brittle-like cracking. Premature failures by brittle-like cracking of Century pipe is known to occur due to poor resin characteristics, excessive local stress intensification caused by improper joints, improper installation, and environments detrimental to pipe long-term strength. All distribution systems containing Century pipe should be monitored to identify pipe subject to brittle-like cracking. Remedial action, including replacement, should be taken to protect system integrity and public safety.

In addition, in light of the potential susceptibility of Century pipe to brittle-like cracking, RSPA recommends that each natural gas distribution system operator with Century pipe revise their plastic pipe repair procedure(s) to exclude pipe pinching for isolating sections of Century pipe. Additionally, RSPA recommends replacement of any Century pipe segment that has a significant leak history or which for any reason is of suspect integrity.

Advisory Bulletin, ADB-97-03, Potential soil subsidence on pipeline facilities.

Pipeline and Hazardous Materials Safety Administration (PHMSA) is advising operators of pipeline facilities of the need for caution associated with heavy rainfall, 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.

Advisory Bulletin, ADB-94-05, Pipelines affected by flooding.

As the result of seven natural gas and hazardous liquid pipeline flood-related failures in or near the San Jacinto River in Texas on October 19-21, 1994, operators should consider the actions recommended in this Advisory Bulletin for application to pipelines located in any area of the United States subject to widespread flooding.

Operators need to direct their re-sources in a manner that will enable them to determine the potential effects of the flooding on their systems, and take actions as appropriate.

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.

Alert Notice, ALN-92-02, Address concerns arising from Allentown, PA explosion.

(1) If a segment of pipeline, including cast iron, is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved; (2) cast iron pipe on which general graphitization is found to a degree where fracture might result, must be replaced; and (3) cast iron pipe that is excavated must be protected against damage.

Alert Notice, ALN-91-02, NTSB Recommendation S P-91-12, 07/90 Allentown PA: replacement of cast iron piping.

Operators should have a program to replace cast iron pipe.

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 Weather related Alert Notices and Advisory Bulletins: **Advisory Bulletin ADB-11-02, Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems** **Advisory Bulletin ADB-05-08, Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Katrina.** **Advisory Bulletin ADB-05-07, Potential for Damage to Natural Gas Distribution Pipeline Facilities Caused by the Passage of Hurricane Katrina.** **Advisory Bulletin ADB-04-04, Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Ivan.** **Advisory Bulletin ADB-98-03, Potential for damage to pipeline facilities caused by the passage of Hurricane Georges.** **Advisory Bulletin ADB-97-01, Potential Damage to Pipelines by Impact of Snowfall, and Actions Taken by Homeowners and Others to Protect Gas Systems from Abnormal Snow Build-up.** **Advisory Bulletin, ADB-92-01, Potential damage to pipeline facilities by Hurricane Andrew.**
Other Reference Material & Source	GPTC Guide Material is available
Guidance Information	1. The operator must have and follow a procedure for continuing surveillance of its pipeline system. This regulation is quite broad in its requirements that it pertains to the entire pipeline system, not just High Consequence Areas. The intent of the regulation is to require the operator to continually assess its pipeline system to detect conditions or issues that can impact pipeline integrity. The operator is expected to detect integrity threatening issues and address them to prevent failures, releases, or others events that may endanger public safety. The regulation specifically identifies changes of class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, but

	also includes the broad category of unusual operating and maintenance conditions. The regulation specifies continuing surveillance, implying that the regulation requires the analysis of integrated pipeline data over time to detect changes, not just reaction to a one-time event. The surveillance should be appropriate for the threats on the pipeline segment and any changes or detection of specific issues should be analyzed to determine if preventative and mitigative actions are required. 2. Some of the factors to consider in determining the adequacy of the operator's continuing surveillance include but are not limited to the following: a. Proximity of the public to the pipelines b. Corrosion history c. Coating condition d. Repair history e. Leak history f. Failures or releases g. Proximity of other pipelines h. Cathodic protection requirements i. The characteristics and vintage of the pipe j. The operating pressure k. Right-of-way conditions l. Depth of cover m. Encroachment n. Proximity to roads and highways o. River and stream crossings p. Overhead crossings q. Flooding r. Subsidence s. ILI's performed (or lack of) t. Blasting u. Nearby construction and development, including road crossings v. Abnormal operations. 3. Final Order Guidance: a. **Northern Natural Gas Company [3-2003-1009] (February 16, 2006):** 49 C.F.R. §192.613(a) requires operators "to establish procedures for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location." If operators follow their own procedures, but are still unable to take appropriate action, regulatory compliance pursuant to §192.605(a) has not been achieved, as the operator must adequately conduct continuing surveillance of its facilities in accordance with the operating procedures established under §192.613(a). CP

Examples of a Probable Violation	1. The lack of a procedure is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator does not have a continuing surveillance procedure appropriate for identifying the conditions or hazards to the pipeline system. 4. The operator has not performed continuing surveillance according to their procedures. 5. The operator fails to take appropriate preventative and mitigative measures based on findings from the continuing surveillance.
Examples of Evidence	1. A copy of the operator's continuing surveillance procedures and associated prescribed documentation. 2. Photographs of field locations showing examples of the conditions or integrity issues that were not identified or addressed by the operator's continuing surveillance program. 3. A description of operator pipeline facility locations and stationing, mile post, or coordinates of integrity issues that should have been identified and addressed by the continuing surveillance program. 4. Inquiries or complaints by the public, other pipeline operators, other agencies, or local authorities on integrity issues involving the operator's pipeline facilities. 5. Documented statements from an operator representative concerning the operators actions taken (or not taken) related to integrity threatening condition that should have been identified by the operator's continuing surveillance program. 6. The operator's pipeline maintenance records, cathodic protection records, rectifier records, ILI data, CIS data, incident reports, valve inspection records, patrolling records, leak detection survey records, etc., and other associated procedures may be needed to support the allegation of a violation of this regulation.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.614
Section Title	Damage Prevention Program
Existing Code Language	(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline shall 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, and the removal of above-ground structures by either explosives 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, other than those located offshore, in Class 1 or 2 locations until September 20, 1995. (3) Pipelines to which access is physically controlled by the operator. (e) Pipelines operated by persons other than municipalities (including operators of master meters) whose activity does not include the transportation of gas need not comply with the following: (10 The requirement of paragraph (a) of this section that the damage prevention program be written; and (2) The requirement of paragraphs (c)(1) and (c)(2) of this section.
Origin of Code	Original Code Document, 47 FR 13818, 04-01-1982
Last Amendment	Amdt. 192-84A, 63 FR 38757, 07-20-1998
Interpretation Summaries	**Interpretation: PI-ZZ-057 Date: 03-24-2004** Regarding §192.614, Paragraphs (a), (d) and (e) of this section exclude operators of certain small gas systems from some requirements, including a written program to prevent damage to that pipeline from excavation activities. Of particular concern is the wording "primary activity" in paragraph (e). (e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following: (1) The requirement of paragraph (a) of this section that the damage prevention program be written; and (2) The requirements of paragraphs (c)(1) and (c)(2) of this section. During our conversation, you advised me that §192.617(e) addresses the exclusion of non- gas companies (such as real estate companies and school campuses). Additionally, the code applies to the company operating the gas system. Ownership of the operating company and what that corporation, or group, does for business is not of concern. Following is our response involving jurisdictional system operators who do not acknowledge responsibility because the system is small or the organization considers gas operation to be a minor part of their business. Response:

	Section 192.614(a) states that "except as provided in paragraphs (d) and (e) 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." Paragraph (d) notes that a damage prevention program is not required for offshore pipelines and pipelines where physical access is controlled by the operator. Section 192.614(e) excludes certain small pipelines from some of the damage prevention program requirements. Section 192.614(e)(1) excludes pipelines operated by persons other than municipalities (including master meter systems) whose primary activity does not include the transportation of gas from the requirement to maintain a written damage prevention program. And, §192.614(e)(2) excludes these pipelines from the requirements at §§192.614(c)(1) and (c)(2) to maintain a list of persons normally engaged in excavation near the pipeline and to notify persons near the pipeline of the damage prevention program. It is important to note that master meter systems and other pipelines operated by persons whose primary activity is not the transportation of gas are only excluded from the requirement to have a written program in compliance with §192.614(a). They are NOT excluded from requirements to provide temporary marking of buried pipelines in the area of excavation (§192.614(c)(5)), to provide for actual notification of persons planning excavations of the temporary marking scheme (§192.614(c)(4)), and to provide for inspection of pipelines near excavations to verify integrity (§192.614(c)(6)). In addition, a gas operator is not excluded from the requirement to have a written damage prevention program merely because they are owned by a larger company whose primary business in not the transportation of gas. The pipeline safety regulations apply to the operator of the gas system. Section 192.614(e) (a) is clearly intended to apply to persons operating gas systems as a minor part of their business. This interpretation of the regulations cannot be altered by general language that may be contained in guidelines and other publications, including *the Training Guide for Operators of Small LP Gas Systems, The Training Guide for Operators of Small LP Gas Systems*, which was sponsored in part by the U.S. Department of Transportation.
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 ADB 04-03, Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities.

RSPA/OPS urges all owners and operators of gas and hazardous liquid pipelines to vigilantly monitor their right-of-ways for unauthorized excavation and the installation of data acquisition devices by third parties seeking to extract product movement information from the pipelines. This activity can impact pipeline integrity either through damage to the pipeline caused by the excavation activities or damage to the pipe coating caused by the attachment of the devices to the pipeline. The installation of pipeline monitoring devices should only be performed with the express knowledge, consent, and support of the pipeline operators.

Damage to underground facilities caused by unauthorized excavation can occur without any immediate indication to the operator. Sometimes a damaged underground pipeline facility will not fail for years after the completion of excavation activities. Excavation equipment does not need to fully rupture a pipeline facility to create a hazardous situation. Damage to coatings and other corrosion prevention systems can increase the risk of a delayed corrosion failure. Escaping and migrating gas can create a safety issue for people living and working near these facilities long after the completion of excavation activities. Leakage from a damaged or ruptured hazardous liquid pipeline can create environmental and safety issues. The primary safety concern is to ensure that excavation operations do not accidentally contact existing underground pipeline facilities. This can be averted by knowing the precise locations of all underground pipeline facilities in proximity to excavation operations and closely monitoring excavation activities.

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	GPTC Guide Material is available 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 §192.605(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. [§192.614(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.[§192.614(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.[§192.614(c)(1)] 4. A damage prevention program must have a process for notification of the public

	in the vicinity of the pipeline.[§192.614(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.[§192.614(c)(3)] 6. The process used to receive and record notifications of planned excavation activities must assure that all notifications are received and recorded.[§192.614(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. [§192.614(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.[§192.614(c)(2)] 10. The operator is ultimately responsible to assure that all of the damage prevention requirements are being performed.[§192.614(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.[§192.614(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.[§192.614(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.[§192.614(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. [§§192.709 and 192.614(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.[§§192.614(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 lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow its written program. 4. An operator does not participate in a qualified one-call system (see §192.614(b)(1) or (2), for receiving and recording notification of planned excavation activities.

	5. 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 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 five years (§192.709). 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, and 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.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.615
Section Title	Emergency Plans
Existing Code Language	(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following: (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator. (2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials. (3) Prompt and effective response to a notice of each type of emergency, including the following: (i) Gas detected inside or near a building (ii) Fire located near or directly involving a pipeline facility (iii) Explosion occurring near or directly involving a pipeline facility (iv) Natural disaster (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency. (5) Actions directed toward protecting people first and then property. (6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property. (7) Making safe any actual or potential hazard to life or property. (8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency. (9) Safely restoring any service outage. (10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible (11) Actions required to be taken by a controller during an emergency in accordance with §192.631. (b) Each operator shall: (1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures. (2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective. (3) Review employee activities to determine whether the procedures were effectively followed in each emergency. (c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to: (1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency; (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

	(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and, (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-112, 74 FR 63310, 12-03-2009
Interpretation Summaries	**Interpretation: PI-97-007 Date: 06-17-1997** Section §192.615(a)(3)(i) allows operators latitude in responding to notices of gas odor inside buildings. As long as an operator's response is "prompt" and is "effective" in minimizing the hazard, there would be little reason, if any, to challenge the appropriateness of the operator's procedures. Given the pros and cons of taking time in a gas emergency to open windows and doors before exiting, we do not think there is sufficient reason to challenge the effectiveness of a response that tells callers to exit quickly without stopping to open windows and doors. **Interpretation: PI-ZZ-039 Date: 07-19-1990** As long as the present DOT standards at 49 CFR §§192.751 and 192.615 remain in effect, OSHA will not attempt to enforce 29 CFR §§1926.651(g)(1)(iii) and 1926.651(g)(2)(i) against employers who are subject to the OPS standards.
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-02-05, Safety of Liquefied Petroleum Gas (LPG) Distribution Systems

Owners and operators of liquefied petroleum gas (LPG) distribution systems should review their compliance with all leak detection, corrosion monitoring, and emergency response procedures, including training of emergency response personnel and liaison with other agencies.

LPG system operators should ensure that their procedures are adequate to detect leaks of heavier-than-air gas. LPG leaks do not dissipate as readily as does the natural gas, which is lighter than air and tends to rise through the soil. Leak detection may also be complicated by extremely wet or frozen soils that effectively cap an area of leaking gas and cause gas that had been venting through the soil into the air to be redirected along underground utility lines or through loosely compacted soils into structures, especially basements. Both these conditions require a leak detection procedure that emphasizes measurement of gas below the surface of the soil or pavement. Usually this is accomplished by ``bar holing'' and examination of below ground areas, such as manholes, storm drains, and basements.

In addition, the gas pipeline safety regulations require an operator to establish and follow written procedures for responding to LPG pipeline emergencies (49 CFR 192.615). This includes establishment of communications systems between utilities, and appropriate fire, police, and other public officials. The regulations also require an operator to establish a continuing educational program to enable customers, the public, and appropriate government organizations to recognize a gas pipeline emergency and to take action to notify the gas operator and local emergency

	responders (49 CFR 192.616). Prompt and effective response is required when gas is detected in or near a building. All actions should be directed to protecting people first through a prompt evacuation of the buildings, followed by establishing access control, elimination of sources of ignition, ventilation, and coordination with emergency responders. **Advisory Bulletin, ADB-01-02, Emergency Plans and Procedures for Responding to Multiple Gas Leaks and Migration of Gas into Buildings.** Owners and operators of gas distribution systems should ensure that their emergency plans and procedures require employees who respond to gas leaks to consider the possibility of multiple leaks, to check for gas accumulation in nearby buildings, and, if necessary, to take steps to promptly stop the flow of gas. These procedures should be communicated to both employee and contractor personnel who are responsible for emergency response to pipeline incidents. **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	GPTC Guide Material is available.
Guidance Information	1. The pipeline operator must have complete emergency procedures that at a minimum cover all of the prescribed topics in the regulations but elaborate on the specific actions the operator will take in the event of an emergency. 2. In addition to the core emergency plan that includes actions that must be taken for

	any emergency, the operator must have site-specific procedures based on the specific facilities at the various locations on the pipeline system. 3. If the operator's emergency plan references other procedures or standards that are not completely contained within the document, the operator should provide cross references to ensure that employees can quickly access and refer to these documents. 4. The operator must train the appropriate personnel in the use of the emergency procedures, must have a program to evaluate the effectiveness of the procedures, and must make modifications to the procedures when found to be ineffective. The operator must have documentation of the training that was provided and evidence of attendance by the appropriate personnel. 5. Operators need to have emergency valves and emergency equipment identified. 6. The operator may provide access to the emergency procedures by means of a computer system but operations personnel still must be able to access the procedures in the event of a computer system outage. All referenced documents, drawings, and maps must also have a backup method for availability in the event of a computer system failure. 7. Actual emergencies must have a process to evaluate the effectiveness of the procedures and make modifications and/or improvements when needed. 8. Operator may use third party vendors or one call associations to provide documentation for meeting with public officials and emergency responders. The operator may also have documentation of additional interaction with the appropriate officials. 9. Emergency plans are required to be reviewed once per calendar year, not to exceed 15 months as required by §192.605. Failure to perform this review should be cited under that section of code. 10. If an operator relies on any third party entity to provide firefighting equipment, manpower, or other resources to respond to meet emergency response requirements as well as the requirements of §192.171, the operator must have documentation showing these agreements and the specific services and equipment that will be provided. 11. 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 systems, etc. §192.615(b) 12. Emergency exercises may be used as part of the emergency plan training. The emergency exercises may include a wide range of activities ranging from tabletop exercises to live drills. The scope of the exercises may vary from a localized emergency to a disaster involving company-wide involvement. These exercises should include a process designed to evaluate the procedures and make changes to improve the operator's response. 13. 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. §192.615(b) 14. It is acceptable to use third parties to conduct meetings with appropriate public officials on behalf of the operators; however, the operator is ultimately responsible for compliance with this requirement. §192.615(c) 15. Documentation must be kept concerning a good faith attempt, and include who

	was invited, who attended, and topics discussed. §192.615(c) 16. Appropriate materials must be sent to the public officials that were invited but did not attend. §192.615(c) 17. The operator should make reasonable attempts to conduct face-to-face meetings with local public officials. §192.615(c)
Examples of a Probable Violation	1. The operator does not have an emergency plan. 2. The operator did not follow its emergency plan. 3. The operator did not provide supervisory or operations personnel the latest version of the emergency procedures for their areas of responsibility. 4. Emergency procedures are not available at locations where emergency response originates. 5. The operator did not follow its procedures during an emergency situation. 6. The operator failed to appropriately classify a notice of an event requiring immediate response. 7. The operator does not have emergency training procedures. 8. The operator did not provide emergency procedures training to appropriate personnel. 9. A written, continuing training program has not been established. 10. Training program procedures are/have not been followed. 11. The operator does not have the required documentation and records for emergencies. 12. During emergencies, the operator failed to communicate appropriately with public officials. 13. The operator has failed to establish and maintain liaison with appropriate police, fire, and public officials as required by this regulation. 14. Maps, drawings, control screens, or other facilities records necessary for an effective response that do not reflect the current configuration of the pipeline facilities. 15. Directories or contacts lists that have not been kept current. 16. No documentation of the required review of emergency procedures (cited under §192.605) 17. No review of emergency response after each emergency. 18. Insufficient documentation of the materials sent or provided to public officials about liaison meetings. 19. No documentation of meetings with appropriate public officials.
Examples of Evidence	1. A Copy of emergency procedures or the applicable portion for the alleged violation. 2. Document any statements made by operator representative about the topic of the alleged violation in the violation report. 3. Obtain written statements from police, fire, or other public officials related to the pipeline operator's emergency response. If they will not provide written statements, document any statements made by police, fire, or other public officials in the violation report. 4. Copies of reports prepared by police, fire, and public officials pertaining to the emergency. 5. Accident investigation documents and accident reports that provide information on the operator's response or failure to respond appropriately.

	6. Photographs of the accident site, including the pipeline facilities and property damage. 7. Documentation of types of meetings, materials covered, invitation lists, and list of those that attended the meeting. 8. Documentation of the assessment review of the effectiveness of the procedures and any revisions that were made from the review. 9. The lack of a plan or documentation.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.617
Section Title	Investigation of Failures
Existing Code Language	Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin, ADB-08-02, Failure of Mechanical Couplings.** This bulletin advises owners and operators of gas pipelines to consider the potential failure modes for mechanical couplings used for joining and pressure sealing two pipes together. Failures can occur when there is inadequate restraint for the potential stresses on the two pipes, when the couplings are incorrectly installed or supported, or when the coupling components such as elastomers degrade over time. In addition, inadequate leak surveys which fail to identify leaks requiring immediate repair can lead to more serious incidents. This notice urges operators to review their procedures for using mechanical couplings and ensure coupling design, installation procedures, leak survey procedures, and personnel qualifications meet Federal requirements. Operators should work with Federal and State pipeline safety representatives, manufacturers, and industry partners to determine how best to resolve potential issues in their respective state or region. Documented repair or replacement programs may prove beneficial to all stakeholders involved.
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. The operator must prepare and follow procedures for conducting a failure analysis, including the assignment of a responsible party for leading or coordinating the investigation, the required participants on an investigation team, procedures for collecting and preserving evidence, maintaining chain-of-custody documentation, documenting the failure site with drawings, photographs, and a written description, performing appropriate laboratory analyses, documenting the findings, and performing a management review. 2. The operator should perform a root cause analysis, determine if similar integrity threatening conditions exist elsewhere on the pipeline system, analyze incident

	information for any trends, and incorporate the findings into the continuing surveillance required by §192.613. 3. The operator's procedures should specifically address requirements to preserve failure surfaces. 4. Operator should have a process to address and conduct post-accident drug and alcohol testing according to the requirements of Part 199 and the operator's procedures. 5. The operator's procedures must include requirements for conducting post-incident drug and alcohol testing according to the requirements of Part 199.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow failure investigation procedures. 4. The operator failed to determine the probable cause of failure. 5. The operator did not take actions to minimize the possibility of recurrence or take actions to determine if similar integrity threatening conditions existed elsewhere on the pipeline system. 6. The operator did not incorporate the findings into a continuing surveillance program. 7. The operator failed to take appropriate actions indicated by an advisory notice.
Examples of Evidence	1. Operator's procedures and related forms. 2. The operator's failure investigation procedures. 3. Operations and maintenance records for the failed facilities. 4. The operator's failure investigation report. 5. The operator's previous failure investigation reports and PHMSA 7100.2 reports. 6. PHMSA alert notices and advisory notices. 7. Operator statements and correspondence. 8. Third party or consultant investigation reports and analyses, including metallurgical evaluations. 9. The operator's SCADA data at the time of failure. 10. The operator's operations control log. 11. The operator's emergency response documentation. 12. Witness statements. 13. Drug and alcohol testing results. 14. An event time line.
Other Special Notations	On February 1, 2011 PHMSA issued a final rule on the reporting of mechanical coupling on reporting requirements failures. This is Section 192.1009 of the Gas Distribution Pipeline Integrity Management – Subpart P.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.619
Section Title	Maximum Allowable Operating Pressure – Steel or Plastic Pipelines
Existing Code Language	(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is 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 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12 ¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 psi. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—		
	Installed before (Nov. 12, 1970)	**Installed after (Nov. 11, 1970)**	**Converted under §192.14**
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

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

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-107, 73 FR 62147, 10-17-2008
Interpretation Summaries	**Interpretation: PI-09-0015 Date: 08-18-2009** The MAOP of a plastic gas pipeline can be upgraded through incremental pressure increases as allowed in §192.557(c). OPS's response was that the §192.619(a)(2)(i) requirement is not the same for steel pipe and plastic pipe. §192.619 requires plastic pipe to be tested at 1.5 times MAOP and incremental pressure increases cannot be used.

Interpretation: PI-ZZ-060 Date: 04-11-2007

"When a temporary launcher or receiver is moved to a new location on the same or a different gas pipeline is a new pressure test required prior to placing the launcher or receiver back into temporary service."

Section 192.503 states that a segment of a pipeline cannot be returned to service after it has been relocated until it has been tested in accordance with Subpart J and Section 192.619 to substantiate the MAOP.

Interpretation: PI-ZZ-059 Date: 04-06-2007

"49CFR192.619(a)(3) allows an operator to establish an MAOP based upon the 5-year window for older systems prior to July 1, 1970. Once that has been established and documented and a class location study is performed resulting in a class location change from what it was on July 1, 1970, does the operator have to incorporate a class location factor for revision of the MAOP established by the 5-year window?

While there is a clause in §192.629(a)(3) which allows the operator to establish the MAOP as the highest actual operating pressure to which a pipeline segment had been subjected to during the 5 year period prior to July 1, 1970, this is only true if that operating pressure is lower than the design pressure or adjusted test pressure as explained in §192.619(a). There is a similar provision in §192.619(c), the "grandfather" clause, which allows an operator to establish MAOP of a pipeline segment at the highest actual operating pressure to which it had been subjected to during the five years preceding July 1, 1970, as long as the pipeline segment is in good condition and the operator considered the segment's operating and maintenance histories.

Regardless, §192.609 requires operators to conduct class location studies to look for population density increases along existing steel pipelines operating at a hoop stress above 40% SMYS. If a class location study identifies a pipeline segment with a hoop stress corresponding to an established MAOP of the pipeline segment using one of the three methods in §192.611(a). Operators must use all the applicable class location factors wherever called for in each of these methods.

Interpretation: PI-ZZ-053 Date: 05-31-2001

Following is our response to a question that a local distribution company (LDC) wants to up rate a steel pipeline in a Class 3 location to a pressure that will produce a hoop stress of less than 30 percent of specified minimum yield strength (SMYS). In 1957, the pipe was pressure tested to 465 psig and the LDC established a maximum allowable operating pressure (MAOP) of 190 psig based on the highest operating pressure during the five-years prior to July 1, 1970. The LDC proposes to raise the pressure from 190 psig to 250 psig in four increments of 15 psig.

The assertion was made that the up rating procedure described above does not meet the minimum requirement of 49 CFR §192.553(d), which states that

> . . . a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location.

We agree that the word "part" as used in §192.553(d) refers to 49 CFR Part 192, rather than just to Subpart K. Therefore, any uprating is limited by the provisions of §192.619.

The uprating regulations in Subpart K do not require that a new pressure test be conducted at the time of uprating. And, §192.555(c), which covers uprating to a pressure that will produce a hoop stress 30 percent or more of SMYS, explicitly allows the use of a previous pressure test as the basis for MAOP, even if the pipeline was not operated to the MAOP during the five years prior to July 1, 1970. Although the use of a previous pressure test is not mentioned in §192.557, which covers up rating to a pressure that will produce a hoop stress less than 30 percent of SMYS, it makes no sense to rely on a previous pressure test for high-stress pipe and to disallow it for low-stress pipe. And, in any case, §192.553(d) clearly states that the new MAOP may not exceed the maximum that we would allow for new pipe of the same material at the same location. Therefore, reliance on a previous pressure test is allowable for uprating to a higher MAOP, providing that the pressure test, de-rated for class location as specified in §192.619, allows for a maximum allowable operating pressure equal to or greater than the proposed uprated pressure.

In response to your specific questions:

Do you agree with our interpretation that the LDC must up rate to a pressure using the table and factors found in 49 CFR §192.619(a)(2)(ii)?

<u>Answer:</u> No. The LDC may follow the uprating procedure in 49 CFR Part 192, Subpart K. The uprated pressure will be limited to the maximum pressure that can be supported by a current or previous pressure test, as de-rated for class location using the factors found in 49 CFR §192.619(a)(2)(ii).

Interpretation: PI-94-033 Date: 10-18-1994

Concerning the maximum allowable operating pressure (MAOP) of a distribution system. The operator established an MAOP of 5 psig, based on a maximum safe pressure under §192.621(a)(5). However, as shown on an MAOP worksheet, the system was operated at 10 psig on a peak day during 1970. The operator now alleges the MAOP was mistakenly set at 5 psig and should have been 10 psig. You ask if the operator may increase the MAOP to 10 psig without uprating under Subpart K of Part 192.

When we addressed this issue in our letter to you dated May 2, 1994, we said the operator must uprate the system under Subpart K. We still believe that is a correct application of the regulations. System MAOP is governed by the lowest value determined under §192.619 and §192.621. The worksheet shows that 5 psig was the lowest value. Thus, 5 psig was unmistakenly [sic] the correct MAOP, and any increase in MAOP must meet Subpart K. However, inasmuch as the system has been operated at 10 psig every winter since 1970, the operator may wish to seek a waiver of Subpart K based on this history of operation.

Interpretation: PI-94-019 Date: 03-23-1994

Concerning the maximum allowable operating pressure (MAOP) of a distribution system. Answers to your question regarding the system follow.

The system has an MAOP of 125 psig based on a maximum safe pressure (§§192.619(b)(6) and 192.621(a)(5)), but the system was operated at 145 psig during the 5-year period prior to July 1, 1970. Section 192.619(c) would allow a new MAOP of 145 psig if the system is now in "satisfactory condition," and the limitations on MAOP under §192.611 (class location change) and §192.621 (high-pressure distribution systems) are met. However, any increase in MAOP above 125 psig must comply with the uprating requirements of Subpart K of Part 192 (§192.551). Subpart K would still have to be met even if the system had been tested after construction to at least 218 psig (1.5 times 145 psig).

Interpretation: PI-94-010 Date: 02-18-1994

In letter to John Searcy, dated March 11, 1974, the second sentence of the second paragraph incorrectly implies that the pressure test required in uprating under §192.557 must be done concurrently with the uprating process. However, the source of the pressure test requirement, §192.619(a)(2)(ii), which limits MAOP on the basis of test pressure, does not prescribe the timing of the test pressure. So any previous test pressure (including any operating pressure that suffices as test pressure) could qualify for uprating under §192.557. Only if the pipeline had not previously pressure tested or if the previous test pressure were insufficient would the pipeline have to be pressure tested concurrently with uprating.

Interpretation: PI-85-002 Date: 03-20-1985

A system was designed for 40 psi but was operated at a maximum of 10 psi for 5 years prior to 07-01-1970. Per OPS, the system MAOP is 10 psi.

Interpretation: PI-82-019 Date: 10-07-1982

Under §192.611(a), an MAOP equivalent to 72% of SMYS may be confirmed for a new Class 2 location. The design pressure referenced in §192.619(a)(1) is based on original conditions, and does not change with changes in Class location.

Interpretation: PI-ZZ-026 Date: 07-10-1981

A pipeline is to be used to transport naphtha and refinery gas. This is allowed if it is qualified for use under §192.14 and it is pressure tested in accordance with Subpart J and the MAOP is determined in accordance with §192.619.

Interpretation: PI-79-031 Date: 08-31-1979

Part 192 requires the installation of overpressure protection at regulator stations which were installed in the 1950's with MAOP based on §192.619(a)(3). Since the regulator stations were installed in the 1950's the overpressure protection requirements of §192.195 would not apply to them unless they have been replaced, relocated, or otherwise changed within the meaning of §192.13. Since MAOP is governed by §192.619(a)(3), they need not have overpressure protection in accordance with §192.195, as they would if §192.619(b) or §192.621(b) applied.

Interpretation: PI-ZZ-023 Date: 08-02-1979

Following is the response to if increasing the pressure in a distribution line to 17 psi which had been in operation for 48 years at a pressure of 5 1/2 ounces can be classified as an "uprating."

The regulations prescribing requirements for uprating (Sections 192.555 and 192.557) are applicable to pipelines which are intended to operate at a pressure higher than the current maximum allowable operating pressure established under 49 CFR 192.619. Therefore, if the established maximum allowable operating pressure for the line in question is less than 17 psi, then the line is subject to the uprating regulations of Subpart K.

Interpretation: PI-78-007 Date: 02-22-1978

Following is the response regarding the test pressure required for a gas "pipeline and riser assembly" installed at an offshore platform. As you point out, Section 192.619(a) (2) (ii) would necessitate a higher test pressure for the riser portion of the assembly if a single maximum allowable operating pressure (MAOP) is to be established. It would be incorrect, therefore, to test the whole assembly only to 1.25 times the proposed MAOP.

You indicate that it may be possible to conduct a pre-installation strength test on the riser portion of the assembly so that the pipeline portion would not have to be designed to withstand a higher test pressure. If so, depending on the factual circumstances involved, such a test may be permissible under the provision of Section 192.505(e).

Interpretation: PI-78-001 Date: 01-04-1978

Would the installation of a 10-inch branch connection on a 24-inch O.D., 0.281-inch wall, grade X-52 pipe in a Class 1 area, using a hot tap and a split full encirclement saddle for reinforcement, require a reduction in the pipe's maximum allowable operating pressure (MAOP) of 850 psig

Under the applicable regulations governing MAOP in this situation (§192.619(a)(1), §192.13(b), §192.105, and §192.111), the pipe's MAOP would be reduced only if installing the 10-inch branch connection "changes" the pipe within the meaning of

§192.13(b) and, if it does, the hot tap with split saddle constitutes a "fabricated assembly" within the meaning of §192.111(d). We have not addressed the second issue because in our opinion installing the branch connection as described would not "change" the existing pipe as intended by §192.13(b). Thus, the installation would not require reassessment of the pipe's design under Subpart C and the MAOP prescribed by §192.619(a)-(c) likewise would remain the same.

Interpretation: PI-ZZ-017 Date: 06-19-1975

Subject to the requirements of Sections 192.621 or 192.623, as the case may be, the maximum allowable operating pressure for a pipeline may not be increased above the lowest pressure determined under Section 192.619(a). For a steel pipeline operated at 100 psig or more, in uprating under Section 192.557 to a pressure permitted by Section 192.619(a)(2)(ii), a pressure test must be performed under that section. Steel pipelines operated at less than 100 psig may be uprated under Section 192.557 to a pressure permitted by Section 192.619(a) without conducting a pressure test.

Interpretation: PI-75-017 Date: 05-01-1975

Does a pressure test made on replacement pipe before it is installed, as permitted by Section 192.719(a)(2), satisfy the requirement of Section 192.619(a)(2)(ii) that in establishing an MAOP for certain pipe, a pressure test be made “after Construction”?

Because the requirements of Section 192.619(a)(2)(ii) and 192.719(a)(2) apply in conjunction, a pressure test permitted by Section 192.719(a)(2) to be made before installation must necessarily qualify as the test required by Section 192.619(a)(2)(ii).

Interpretation: PI-ZZ-012 Date: 05-30-1974

To comply with Part 192, an operator who acquires an existing plastic pipeline other than one relocated or replaced after November 12, 1970, need not know what pressure test was made after installation of the line. However, since the line’s MAOP cannot be determined under §192.619(a)(2)(i) without this information, the operator must establish an MAOP by testing the line, unless the exception of §192.619(c) applies.

An operator who acquires a new steel pipeline or one relocated or replaced after November 12, 1970, must obtain or establish the test record required by §192.517, if applicable to the line acquired. Irrespective of this recordkeeping requirement, in the case of a new steel pipeline or a relocated or replaced one, to comply with Subpart J an operator must know what pressure test was made after installation or conduct a proper test. In the case of an existing steel pipeline operated at 100 psig or more, other than one relocated or replaced, to establish an MAOP under §192.619(a)(2)(ii), an operator must know what test was made after installation or conduct a proper test, unless the exception in §192.619(c) applies. Where such an existing line is operated at less than 100 psig, an MAOP may be established under §192.619(a) in the absence of a post installation test.

Interpretation: PI-73-014 Date: 06-19-1973

"…..under 192.619 and 192.621. If a gas system is an all steel system and designed and tested for a 100 lb. system and has only operated at 30 lbs. for the last ten years, what is its MAOP?"

This system is governed by §192.619(c) which, in effect, allows the pipeline to operate at the highest actual operating pressure to which it was subjected during the 5 years preceding July 1, 1970. In the given case, the system operated at only 30 lbs. in that 5 year period. The MAOP is, therefore, 30 lbs.

Interpretation: PI-73-008 Date: 02-13-1973

The letter asked us to verify that §192.619(b) and §192.621(b) of Title 49 of the Code of Federal Regulations provide for installation of overpressure protective devices for gas systems that have a maximum operating pressure determined by the corrosion history of the pipe segment. You indicated in your telephone conversation with Mr. DeLeon that it appeared to you that these two sections were in conflict with §192.195 and §192.197 which do not apply to installation of overpressure protective devices on systems built prior to March 12, 1971, or systems which were replaced, relocated, or otherwise changed prior to November 12, 1970, pursuant to §192.13, 49 CFR.

The requirements of §192.195 and §192.197 are contained in Subpart D of Part 192 which prescribes minimum requirements for the design and installation of pipeline components and facilities. Sections 192.619 and 192.621, on the other hand, are operational requirements contained in Subpart L. Section 192.603(a) makes clear that no person may operate a segment of pipeline unless it is operated in accordance with the requirements of Subpart L. Subpart L sets forth the continuing requirements necessary to insure safe operation of a pipeline independent of the initial design, installation and construction requirements that were applicable to that pipeline. Sections 192.619(b) and 192.621(b) prescribe requirements for the operation of pipeline facilities regardless of when these pipelines were installed. Therefore, compliance is required with both of these sections in the operation of the gas facilities.

Interpretation: PI-72-035 Date: 08-09-1972

The letter asked whether a hydrostatic pressure test was required on a pipeline. If the operating company plans to pressure test the replacing section of pipe in the operating pipeline, then the pressure test would have to be made with air or water since the permissible test pressure in a Class III location using gas, as set forth in Section 192.503(c), falls just short of that required to comply with Section 192.619(a)(2)(ii). However, gas, air, or water could be used on the fabricated short section of pipe at some other location than in the pipeline.

Interpretation: PI-ZZ-004 Date: 11-03-1971

Our regulations do not specify a test pressure above the desired operating pressure for service line operating in the range of 90 psig to 20 per cent of SMYS. However,

the requirement that is specified in §192.619(a) (2) revised. This paragraph specifies that in order to operate a pipeline at 100 psig or more, it must be tested according to the limits shown in the table incorporated in the regulation.
According to §192.619(a)(2)(ii) the test pressure for new Lines to operate over 100 psig will always exceed the maximum allowable operating pressure. The only situation where a test pressure of a new pipeline is less than the permitted operating pressure is for the line that will operate between 90-100 psig. This variation was included based on strong recommendations of industry and TPSSC who claimed there was too much existing equipment designed for 100 psig output but incapable of achieving much over 90 psig. Also, since this is a leak test not a strength test, it was concluded there was little likelihood of there being any detrimental effect on safety.

Interpretation: PI-71-057 Date: 06-04-1971

The letter asked for an opinion on the effect of the "grandfather" clause in §192.619(c) vis-a-vis the requirements in §§192.607 and 192.611 that an MAOP of a pipeline which is not commensurate with its present class location must be confirmed or revised in accordance with §192.611.

When Part 192 was issued, the preamble indicated the primary purpose of the "grandfather" clause was to avoid reductions of the existing MAOP's because the pipeline was only tested to 50 psig above MAOP or because the pipeline was operated at pressures above the design stress levels permitted under §192.619(a). However, the right conferred by this "grandfather" clause are somewhat circumscribed by the phrase "subject to the requirements of §192.611".

Section 192.611 was derived from provision in the ANSI B31.8 Code (850.42) which was specifically limited to pipelines in Class 2, 3, or 4 locations. Although this limitation was not included in Section 192.611, we note that the provisions of that section can only be meaningfully applied to pipelines in Class 2, 3, or 4 locations. Nowhere in this section is there a reference to a pipeline in a Class 1 location.

Therefore, it is our opinion that pipelines in Class 2, 3 and 4 locations must have their operating pressures confirmed or revised in accordance with Section 192.611. However, pipelines in Class 1 locations operated at pressures which are not commensurate with that class location, based on the design stress levels of Section 192.619(a)(1), may continue to operate at their previous MAOP under the "grandfather" clause of Section 192.619(c). In answer to the specific questions -- the first pipeline could continue operations at the stress level of 75% of SMYS; pressure in the second or third pipeline would have to be confirmed or revised in accordance with Section 192.611.

Interpretation: PI-ZZ-001 Date: 12-03-1970

Section 192.619 establishes a maximum allowable operating pressure for all steel and plastic pipelines. The requirements of Section 192.621 are additional requirements which apply to high-pressure distribution systems, defined in Section 192.3 as those systems in which the gas pressure in the main is higher than the

	pressure provided to the customer.
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	GPTC Guide Material is available. Transportation Safety Institute - Determination of Maximum Allowable Operating Pressure in Natural Gas Pipelines. Date: 04-22-1998 ASME B31.8-2007, "Gas Transmission and Distribution Piping Systems", November 2007.
Guidance Information	1. Section §192.619 is used to determine MAOP of a specific pipeline segment. 2. An operator must have some means that will ensure that the MAOP is not exceeded during normal operations. 3. The intent of §192.619(c) is to allow existing pipeline segments to continue operating at a specified pressure which will not exceed MP5 (maximum pressure in the five years prior to a pipeline segment becoming regulated). 4. MAOPs based on MP5 pressure gradients may still apply. As an example, the MP5 pressure at the discharge side of compressor station A may be greater than the MP5 pressure at the suction side of compressor station B. In this case, established MAOPs along a segment or section may differ. The guiding principal is that the MAOP of an element inside the segment cannot exceed its old (MP5) operating level. 5. MAOPs for pipelines and all associated appurtenances established under 192.619(c), pipelines and all associated appurtenances may operate at an MAOP where stresses exceed the SMYS limits of §§192.619(a)(1), 192.105, and 192.111. 6. Regardless of when placed in service, pipelines that have changes in class to Class 2, 3 and 4 locations cannot operate above the hoop stress that is commensurate with the present class location, unless the MAOP has been confirmed or revised (or is being confirmed or revised due to a recent class location change) in accordance with §192.611. Segments with MAOP established by §192.619(c) with class changes are not exempted from the requirements of §192.611. 7. Operators may not design or set normal pressure controlling devices such that any part of any pipeline segment exceeds its prescribed MAOP.

	8. Operators may not exceed MAOP for such purposes as temporarily applying a pressure boost in an attempt to dislodge a stuck pig, during times of high demand rates, or other operational upset conditions. 9. §192.619(a)(2)(ii) permits operators to rely on previous test pressures in calculating MAOP, as long as the segment was tested between July 1, 1965 and July 1, 1970, and there is nothing in the regulations that alters this policy when MAOP is determined by up-rating. 10. The "desired maximum pressure" of facilities is not defined or specifically regulated by Part 192. However, the operating pressure of a pipeline may not exceed its maximum allowable operating pressure (§192.619 and §192.623) or any lower pressure that might be required as a remedial measure for safety (e.g., §192.485). 11. The maximum safe pressure as defined in §192.619(a)(4) should only be used to derate or lower an established MAOP. 12. Additional MAOP requirements are available under §192.620 for pipeline operating at an alternate MAOP. 13. For overpressure requirements, see §192.201 and §192.739.
Examples of a Probable Violation	1. Operator's listed MAOP exceeds the criteria of §192.619. 2. All applicable elements required in a MAOP calculation were not adequately documented. 3. Actual operating pressure exceeded MAOP, without the occurrence of an equipment malfunction or failure. 4. Operator has no means to prevent the pipeline from being operated above the MAOP. 5. No records to substantiate the established MAOP.
Examples of Evidence	1. Records used to substantiate MAOP, such as: a. MP5 records b. Uprating records c. Pressure test records d. Pipe and component specifications e. Segment class designations. 2. Diagram of the system showing existing pressure-limiting devices. 3. Photographs of field equipment. 4. Segment operating pressure records (charts and SCADA information).
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.625
Section Title	Odorization of Gas
Existing Code Language	(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the

	gas is readily detectable by a person with a normal sense of smell. (b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless: (1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location; (2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975: (i) An underground storage field; (ii) A gas processing plant; (iii) A gas dehydration plant; or (iv) An industrial plant using gas in a process where the presence of an odorant: (A) Makes the end product unfit for the purpose for which it is intended; (B) Reduces the activity of a catalyst; or (C) Reduces the percentage completion of a chemical reaction (3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process. (c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following: (1) The odorant may not be deleterious to persons, materials, or pipe. (2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed. (d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight. (e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant. (f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by - (1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and (2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-93, 68 FR 53895, 09-15-2003
Interpretation Summaries	**Interpretation: PI-ZZ-058 Date: 04-05-2004** An operator owns 2.7 miles of an 86.7 mile continuous pipeline. More than 50% of the 2.7 miles is Class 3 while the remaining 84 miles, owned by another operator, is Class 1. Does the owner of the 2.7 miles have to odorize? Answer: No. Odorization is not dependent on ownership.

Interpretation: PI-ZZ-054 Date: 09-05-2001

Operator requested to be allowed to install gas detectors in their compressor stations instead of odorizing gas. Response: operator's compressor stations are in Class 1 and 2 locations and do not require odorization.

Interpretation: PI-ZZ-042 Date: 02-11-1993

No violation exists if an operator finds an inadequate level of odorant in his distribution system as long as immediate corrective action is taken.

Interpretation: PI-82-007 Date: 05-06-1982

FACTS:

I. An industrial customer received unodorized gas from a pipeline which operated at greater than 20 percent SMYS, passed through class 1 and 2 locations, prior to May 5, 1975. The customer used the gas for purposes and processes which did not require nor would have been affected by a malodorant additive. In 1979, the customer began hydrogen production which required unodorized gas, in that, malodorant sulfur compounds severely affect catalyst activity. During 1980, it was determined that the class location along the pipeline from the end and upstream for several miles had changed to class 3.

QUESTION 1: Is the pipeline, in the class 3 locations, exempt from odorization?

INTERPRETATION: The facts presented indicate that prior to May 5, 1975; the line in question was a transmission line because it operated above 20 percent of SMYS. If the line is still properly classified as a transmission line, the new class 3 portion of the line may qualify under §192.625(b)(3) for an exemption from the odorization requirement if the line is a lateral transmission line transporting gas to a "large volume customer" with at least 50 percent of the length of line in class 1 or 2 areas. By prior interpretation, a "large volume customer" is in effect a "distribution center" for purposes of classifying a pipeline as a "transmission line" under the definition of that term is §192.3, and the term "large volume customer" is used consistently here in applying §192.625(b). The class 3 portion would not qualify for an exemption under the industrial plant provision of §192.625(b)(2)(iv) because the current condition under which odorants are said to be detrimental arose after May 5, 1975.

QUESTION 2: If there are 30 other customers along the pipeline not requiring unodorized gas, does the one which requires unodorized gas govern the determination?

INTERPRETATION: The exclusion of a class 3 pipeline from the odorization requirement depends on whether the pipeline is a transmission line that falls within one of the exemption provisions of §192.625(b). The number of customers along a transmission line that are not troubled by receiving odorized gas is not a factor in applying §192.625(b). Thus, for purposes of §192.625(b)(2) or (b)(3), only one customer can qualify to exempt the entire upstream class 3 or 4 portion or portions of the line from the odorization requirement, even though in the case of paragraph (b)(2), the customer receives gas via a service line connected to the transmission line. Any of the customers along an unodorized transmission line that receive gas via a service line would have to be supplied odorized gas under §192.625(a).

QUESTION 3: Is it necessary that the **process** requiring unodorized gas was **performed** before May 5, 1975, or just that unodorized gas was **served** before May 5, 1975, to create an exemption under §192.625(b)(2)?

INTERPRETATION: This question is answered in the answer to Question I.1. Amendment 192-21 (40 FR 20279) which established §192.625(b)(2) makes it clear that the exemptions were intended to remedy existing problems and were not intended to apply to future conditions. Similar but new problems may be handled under the waiver process of Section 3 of the Natural Gas Pipeline Safety Act of 1968.

FACTS:

II. A pipeline has been called a transmission line, but through the years numerous customers have been added and population density has increased along the line.

QUESTION 1: When and/or under what conditions would this pipeline become a distribution main?

INTERPRETATION: The classification of a pipeline as a transmission line or main is determined by applying the definitions under §192.3. Under the definition of "transmission line," the number of customers along a line is not one of the three conditions that qualify a pipeline as a transmission line. Thus, regardless of the number of customers added to a transmission line during its life, it remains a transmission line as long as it continues to meet any of the qualifying conditions. If a gas pipeline no longer qualifies as a transmission line and it is not a gathering line, then according to the definitions, it is a distribution line and a "main" if it serves more than one customer.

QUESTION 2: Does it make difference if all of the customers are large industrial customers, located in a densely populated area?

INTERPRETATION: In accordance with the definition of "transmission line," the addition of large industrial customers to a line is not a reason to reclassify the line as a main.

Interpretation: PI-80-015 Date: 09-10-1980

A farm tap from a transmission line is used to deliver gas to a restaurant directly from a transmission line. Gas in the transmission line is not required to be odorized. Does the gas in the service line have to be odorized?

§192.625(a) requires that gas in distribution lines have a natural odor or be odorized to the limit prescribed. Since service lines are distribution lines, they are subject to the odorization requirements of §192.625(a). The exception from odorization provided by §192.625(b) for some transmission lines does not affect the requirement to odorize gas in distribution lines connected to an unodorized transmission line.

Interpretation: PI-79-010 Date: 03-23-1979

On odorizing equipment that is not equipped to measure the injection rate or the volume of odorant in the odorizer tanks, the tanks would at least have some means of indicating when they are full. An operator can determine the number of pounds of odorant required to fill the odorizer tanks and by reading the gas meter determine the quantity of gas used since the odorizer was last filled. From this, the pounds of odorant per million cubic feet of gas can be determined and compared with other periods. Filling of odorizers and reading of gas meters should be often enough to assure continuous odorization of gas delivered and should be done, in so far as is practicable, near the times when the system gas load characteristics are expected to change. These changes should be readily anticipated by operators having knowledge of the customer gas usage characteristics and at seasonal or other weather changes such as extreme cold weather.

Interpretation: PI-79-001 Date: 02-06-1979

The 18 month requirement has been changed to 24 months under the current revision to §192.611.

The letter asked how much time is permitted under Part 192 to make system changes (in particular odorization) necessitated by class location changes.

While §192.613(a) requires an operator to make necessary changes, no time period for compliance is specified. However, a similar provision under §192.611(c) requires confirmation or revision of MAOP within 18 months after a change in class location. In view of this similarity, it appears that an 18-month compliance period is appropriate to apply under §192.613(a). In a previous interpretation, we have stated that the 18-month period begins to run upon completion of a structure which results in a new class location. (See §192.611 interpretation of 05-12-78)

Interpretation: PI-73-030 Date: 10-24-1973

The letter indicates that the gas system concerned is an intermediate pressure (typically 25 psi) distribution system, serving the buildings on a college campus and owned by the college. Gas is supplied through a regulator-metering station from odorized mains of a gas service utility company. The system comprises approximately 4.5 miles of welded steel mains and service lines 5 inch to 1 1/2 inch diameter, serving 45 regulators at campus buildings, installed largely prior to 1970. Cathodic protection was installed in June 1971, monitored weekly at key points by owner-personnel, and checked so far at 16-month intervals by a corrosion engineer.

	The gas system as described raises the jurisdictional question of whether the pipelines on the college campus constitute a master meter system subject to the Federal gas pipeline safety regulations or whether the college is the ultimate customer and therefore the lines in the college are not subject to the regulations. In order to assist you in making this determination, if the college owned gas system consumes the gas and provides another type of service such as heat or air conditioning, to the individual buildings, then the college is not engaged in the distribution of gas. In this instance the college would be the ultimate consumer, and the Federal pipeline safety standards would only apply to mains and service lines upstream of the meter. If the college owned gas system provides gas to consumers such as concessionaires, tenants, or others, it is engaged in the distribution of gas, and the persons to whom it is providing gas would be considered the customers even though they may not be individually metered. In this situation the pipelines downstream of the master meter used to distribute the gas to these ultimate consumers would be considered mains and service lines subject to the Federal pipeline safety standards. The answer to this specific question is predicated on the assumption that this system is a distribution system subject to the jurisdiction of the Federal pipeline safety standards. Question 4. Are periodic tests of odorization per §192.625 required of the owner or is he covered by tests made by the supply utility company? Answer. Section 192.625(f), 49 CFR, requires that each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available. AGA XQ0005, Odorization Manual ASTM D6273, Standard Test Methods for Natural Gas Odor Intensity Transportation Safety Institute, Odorization Papers.
Guidance Information	1. The one-fifth LEL is based on the operators' gas composition. 2. Sniff tests are qualitative tests that should be performed by individuals with a normal sense of smell. Considerations such as gender, age, smoking habits, colds, and other health-related conditions such as allergies or colds that could affect the sense of smell should be considered in selecting individuals to perform sniff tests.

	3. Records should reflect the person actually doing the sniff test. 4. Some operators conduct sniff tests with two individuals, to get more conclusive results. 5. Test locations to verify odorant levels should include system end points (extremities). 6. Operators must have written procedures for the testing of odorization. 7. Operator needs to specify the frequency of odorization tests. 8. The operator should retain records of the odor level and odorant concentration test results. 9. Odorizer injection rates are not stand alone proof of adequate odorization. 10. Special attention to odorization requirements should be applied to transmission (and transmission laterals) lines where class 3 areas exist. 11. Class location studies are needed to substantiate unodorized pipelines. 12. Operator’s line designation plan may help in the determination of line classification of transmission or lateral.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written odorization procedures. 4. The operator is not odorizing a pipeline segment that has to be odorized. 5. The odorant is not detectable as per §192.625(a) at the one-fifth of the lower explosive limit of the gas, or is injected without wide variation. 6. The operator is odorizing a pipeline, but the odorant is deleterious to persons (materials or pipes) in violation of §192.625(c)(1). 7. The operator is odorizing a pipeline but, the products of combustion from the odorant are toxic, corrosive, or harmful when breathed. 8. The operator is odorizing a pipeline and is using up the remnants of a batch of odorant which, laboratory test records show is soluble in water to an extent greater that 2.5 parts to 100 parts by weight in violation of §192.625(d). 9. The operator is odorizing a pipeline but, the amount of odorant induced by the odorizer varies considerably over time and is inconsistent, in violation of §192.625(e). 10. The operator is odorizing a pipeline but company records do not substantiate that the operator is conducting periodic sampling of the combustible gas to assure the proper concentration of odorant in accordance with §192.625(f). 11. The operator is only using injection rates for proof of odorization. 12. The percent of air in gas was improperly calculated after odorant sampling.
Examples of Evidence	1. Operator’s procedures. 2. Records and documentation of odorizer inspections, calibrations, or tests. 3. Records of sniff tests. 4. Operator’s field checklists or procedures used for operating an odorizer. 5. Documented statements from operator. 6. The lack of procedures or documents.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.627
Section Title	Tapping Pipelines Under Pressure
Existing Code Language	Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Summaries	**Alert Notice, ALN-87-01, Incident involving the fillet welding of a full encirclement repair sleeve on a 14" API 5LX-52 pipeline.** 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	GPTC Guide Material is available. API RP 2201, Safe Hot Tapping Practices in the Petroleum & Petrochemical Industries
Guidance Information	1. Whenever an operator makes a tap on a pipeline under pressure (hot tap), it must be performed by an individual qualified to make hot taps. 2. Qualification must be available and supported by appropriate records or equivalent documents. 3. It is acceptable for an operator to use the procedures as provided by the hot tap equipment manufacturer, as long as an associated reference is in the operator's procedures. It is the operator's responsibility to ensure (find other appropriate words used in other sections).
Examples of a	1. The lack of procedures is a violation under §192.605.

Probable Violation	2. The lack of records is a violation under §192.603. 3. The operator performed (or contracted) hot taps on a pipeline under pressure using a crew or individual that was not qualified to make hot taps.
Examples of Evidence	1. Sections of the operator's procedures. 2. Records and documentation of pipeline repairs that required hot taps. 3. Operator statements. 4. Photographs. 5. Qualification records. 6. The lack of procedures or documents.
Other Special Notations	1. Other factors to be considered when performing hot taps: a. UT examination of pipe wall should be performed to identify possible laminations, wall thinning or other defects, prior to selecting final tap location. b. Pressure testing and NDT of the welded fitting should be performed to ascertain the integrity of the weld, prior to tapping the carrier pipe.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.629
Section Title	Purging of Pipeline
Existing Code Language	(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas. (b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available. Section 4 of Guide Material for §192.751 AGA XK0101, “Purging Principles and Practice”
Guidance Information	1. The operator should determine the time required to complete the purge operation to assure that gas-air mixtures are minimized. 2. Instruments may be used to verify completion of purge. 3. Selection of gas venting location should not be near electric high voltage lines, or other overhead obstructions. 4. The operator must have written procedures for performing purging operations.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures. 4. The gas/air was not released into the line in a moderately rapid and continuous flow, resulting in the formation of a hazardous mixture. 5. The gas/air was not supplied in sufficient quantity, resulting in the formation of a

	hazardous mixture.
Examples of Evidence	1. Operator's procedures. 2. Records and documentation of any pipeline purging operations. 3. Operator field checklists or procedures used during purging operations. 4. Documented statements from operator. 5. The lack of procedures or documents.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.703
Section Title	General
Existing Code Language	(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart. (b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. (c) Hazardous leaks must be repaired promptly.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-70
Last Amendment	
Interpretation Summaries	**Interpretation: PI-ZZ-065 Date: 05-22-1998** The only safety standard in Part 192 that governs the maintenance of service line valves is §192.703(b). This section requires the repair, replacement, or removal from service of any segment of pipeline, including a valve that is unsafe. Although the inability to operate a service line valve may be reason to apply §192.703(b), Part 192 does not require inspection of service line valves to see if they are operable. **Interpretation: PI-89-021 Date: 09-27-1989** The letter requested clarification of our August 31, 1989, letter regarding protection for offshore pipelines. The requirements of 49 CFR 192.317(a) applies to conditions known or that can be foreseen at the time of construction. Thereafter, an operator does not have a continuing obligation under this rule to provide protection against hazards from changed or new conditions. However, if the operator learns the pipeline has become unsafe due to these changed or new conditions, the operator would have to take remedial action as required by 49 CFR 192.703(b). **Interpretation: PI-83-002 Date: 02-10-1983** §192.703(b) states that each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. This requirement applies to all pipeline segments, regardless of the construction date. **Interpretation: PI-ZZ-029 Date: 11-03-1982** The letter concerns the use of an encapsulation method to repair leaks in PVC fittings. The question addressed is whether the method would qualify as a "patching saddle" under §192.311. The enclosed copy of a letter dated February 27, 1981, to Keith Chen Discusses the meaning of "patching saddle." Based on that discussion, it appears that the encapsulation method does not qualify as a "patching saddle" in its ordinary sense.

We presume that the primary use of the method would be to repair existing pipelines in place. In this case, §192.311 would not apply since it only governs the construction of new transmission lines and mains or existing ones that are being relocated, replaced, or otherwise changed (see §§192.13 and 192.301). The only restrictions under Part 192 on use of the encapsulation method for repairing an existing plastic pipeline are the provisions in §192.703(b), which essentially require that the repair method used remit in a safe pipeline.

Interpretation: PI-81-005 Date: 02-25-1981

The letter concerns the use of full encirclement stainless steel band clamps for permanent repair of damaged plastic pipe. Even if the band clamp were considered a "patching saddle," as intended by §192.311 (which it is not), its use to permanently repair plastic pipe either during construction or after operation may be prohibited under §192.703(b).

Because of the question of cold flow of plastic pipe, we believe that the safety of a permanent repair by use of a band clamp is questionable under some conditions, depending on the stiffness of the elastic pipe involved. Where unsafe conditions would result, §192.703(b) would forbid use of the band clamp as a repair method.

Interpretation: PI-77-013 Date: 05-01-1977

The letter describes a proposal to enlarge a highway right-of-way which is located over an existing gas pipeline. The specific question is whether the Federal gas pipeline safety standards would require upgrading or encasing those portions of the existing pipeline which lie within the limits of the proposed new right-of-way.

In addition to Section 192.111, Sections 192.613 and 192.703(b) may also apply to the situation of establishing a new highway right-of-way over an existing pipeline.

Interpretation: PI-77-003 Date: 01-26-1977

While a paved roadway may be considered a "structure" as that term is used under Section 192.327(c), that section of the safety standards does not appear applicable to the situation described. Section 192.327 prescribes minimum cover requirements which must be met when a pipeline is readied for service or replace, relocated, or otherwise changed. The rule does not have continuing legal effect thereafter, and once cover is installed, it need not be maintained in accordance with §192.327. However, if cover over an existing pipeline is eroded or otherwise removed, as by grading, an operator who knows of the reduction in cover is required by Sections 192.613 and 192.703 to consider the effect of the loss of cover on the safety of the pipelines and take appropriate remedial action if necessary.

Interpretation: PI-76-066 Date: 10-04-1976

	To provide for safe operation of pipelines, the maintenance requirements of §§192.739 and 192.743 apply to all relief devices on a pipeline whether or not their installation is required by §192.195. This unrestricted application is indicated by §192.703 which provides - "No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart." **Interpretation: PI-75-052 Date: 10-30-1975** Construction of a building over a pipeline may result in a change in the class location of the pipeline or the pipeline's being generally unsafe. In that event, the operator must take remedial action required by Sections 192.611, 192.613, or 192.703, as appropriate. **Interpretation: PI-75-023 Date: 05-29-1975** The letter asks what criteria should be used in determining whether the pipeline should remain in place or be relocated. The Federal gas pipeline safety standards in 49 CFR Part 192 for the design, installation, and testing of pipelines would not apply to the existing pipeline unless it is replace, relocated, or otherwise changed as a result of constructing the road. Standards for operation and maintenance of the pipeline in 49 CFR 192.613 and 192.703(b) would require, however, that the pipeline be evaluated for safety purposes as a result of the road construction and appropriate remedial action taken, if necessary, in accord with those sections. **Interpretation: PI-ZZ-006 Date: 08-04-1972** "Is there a criterion as to the time that a leak must be repaired in a gas pipe line or distribution system?" Section 192.703 of the Federal gas pipeline safety standards provides in paragraph (b) that each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service, and further provides in paragraph (c) that hazardous leaks must be repaired promptly. Which leaks are "hazardous," which leaks make a pipeline "unsafe," and whether a repair has been done "promptly," depends upon the nature of the operation and local conditions? The nature and size of the leak, its location, and the danger to the public are among the factors that must be considered by the operator. These same factors would be considered in determining whether a penalty should be imposed for failure to comply with the requirements of Section 192.703.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available.

Guidance Information	1. Operators need to repair of conditions that are "unsafe" or "could adversely affect the safe operation of [the] pipeline system," but do not specify a time period in which the required repairs must be made. 2. Operator needs to define hazardous leak. Part 192 Subpart P defines hazardous leaks. While this definition is only applicable to distribution systems, it may provide guidance for defining hazardous leaks. See §192.711 for additional guidance material. 3. Operator needs to have a leak classification system if all leaks are not repaired promptly. 4. Operator needs to have written procedures for leak classification and defining required repairs including time frames for performing repairs. 5. Operator must have a process for documenting leaks.
Examples of a Probable Violation	1. The lack of a procedure is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures. 4. Operator does not have a leak classification process. 5. Pipelines known to be unsafe are not repaired. 6. Operator did not perform repairs in a timely manner or in accordance with their procedures.
Examples of Evidence	1. Operator’s written procedures. 2. Leak classifications. 3. Leak repair records. 4. Incident reports. 5. SRCs. 6. The lack of procedures or documents.
Other Special Notations	

<table>
<tr><td>Enforcement Guidance</td><td>O&M Part 192</td></tr>
<tr><td>Revision Date</td><td>12-07-2011</td></tr>
<tr><td>Code Section</td><td>§192.705</td></tr>
<tr><td>Section Title</td><td>Transmission Lines – Patrolling</td></tr>
<tr><td>Existing Code Language</td><td>(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.
(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

<table>
<tr><th rowspan="2">Class location of line</th><th colspan="2">Maximum interval between patrols</th></tr>
<tr><th>At highway and railroad crossings</th><th>At all other places</th></tr>
<tr><td>1,2..........</td><td>7 1/2 months; but at least twice each calendar year</td><td>15 months; but at least once each calendar year</td></tr>
<tr><td>3.............</td><td>4 1/2 months; but at least 4 times each calendar year</td><td>7 1/2 months; but at least twice each calendar year</td></tr>
<tr><td>4.............</td><td>4 1/2 months; but at least 4 times each calendar year</td><td>4 1/2 months; but at least four times each calendar year</td></tr>
</table>

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.</td></tr>
<tr><td>Origin of Code</td><td>Original Code Document, 35 FR 13248, 08-19-1970</td></tr>
<tr><td>Last Amendment</td><td>Amdt. 192-78, 61 FR 28786, 06-06-1996.</td></tr>
<tr><td>Interpretation Summaries</td><td>Interpretation: PI-ZZ-049 Date: 09-22-2000

Part 192 does not give the right of operators to remove trees along a ROW where landowner agreements and local land use controls may dictate otherwise. Where trees obscure the use of aerial patrols, walking or driving patrols may be employed.

Interpretation: PI-91-015 Date: 05-28-1991

The regulations do not require that trees be removed or that rights-of-way be inspected from the air. It is the position of the Department that, if visual aerial inspections are used by the operator to meet the requirements of the regulations, the rights-of-way must be kept clear of brush and trees. Normally, this is a matter subject to negotiation in the rights-of-way agreement between the pipeline</td></tr>
</table>

	companies and the landowners involved. **Interpretation: PI-89-023 Date: 10-18-1989** Aerial videotaping could be an acceptable part of the process of complying with the standards. **Interpretation: PI-ZZ-038 Date: 05-22-1989** This office administers the DOT regulations that govern the transportation of gas by pipeline, (49 CFR Parts 191, 19. and 199). These regulations do not prohibit the relocation of gas pipelines within rights-of-way. **Interpretation: PI-ZZ-020 Date: 08-27-1976** An operator cannot require a landowner to remove trees over a right-of-way based on the requirements of this Code Section.
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.** This advisory bulletin is issued 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.
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. Operator needs a written patrol procedure that considers all factors listed in regulation. 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, blowing gas & debris,

	product, sheen or bubbles on the water, and/or odor. b. Indication of construction activity may include clearing or cutting of trees or vegetation, heavy equipment including directional drilling on or near the ROW, exposed soil or dirt mounds on the ROW c. Evidence of unauthorized pipeline crossings d. Evidence of blasting on or near the ROW. e. Dredging activities on a waterway in the ROW crossing vicinity, a building, fence or shed, on or near the ROW. f. 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. g. Areas of continual earth moving activities (i.e. gravel/sand pits, quarries, landfills, etc.) h. Pipe spans, bank or shoreline erosion at water crossings, and removal of rip rap. i. Landslides, flooding, exposed pipe. j. Dumping or burying of trash on ROW. k. Damaged or missing pipeline markers. l. New buildings, fences, or other encroachments on the ROW. m. Changes in land use on the ROW n. If aerial patrols are used, trees or vegetation obscuring the ROW. 3. Aerial Patrols should take into consideration factors that affect the ability to adequately observe the pipeline ROW such as angle of sunlight, and shadows cast on the ROW, and seasonal factors affecting vegetation that would conceal or not reveal signs of leakage. Weather factors such as extended drought may mask signs of leakage. 4. Surface patrols should be used when conditions do not allow aerial patrols to provide adequate observation of the ROW 5. Final Order Guidance: a. ***Natural Gas Pipeline Company of America* [4-2003-1005] (Oct. 21, 2004):** County roads open to public use are considered “highways” for purposes of determining the maximum intervals between patrols under 49 C.F.R. §192.705(b). CO/CP
Examples of a Probable Violation	1. The lack of a procedure is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow procedures. 4. Operator does not meet the minimum class defined patrolling requirements. 5. The frequency of patrols is inadequate as determined by the size of the line, operating pressures, class location, terrain, weather, and other relevant factors. 6. For aerial patrols, tree canopy and vegetation overgrowth not adequately trimmed, inhibiting the ability to evaluate surface conditions. 7. When the route of a surface patrol does not provide adequate observation of the ROW. 8. The patrol program fails to promptly communicate critical patrol intelligence to assure the safety and operation of the pipeline. 9. Inadequate documentation of patrol follow-up activities, including dates. 10. When aerial patrols cannot be performed due to weather conditions, other types of patrols were not used as backup. 11. Materials stored on the ROW interfere with the ability to patrol the ROW.

Examples of Evidence	1. Documentation showing that the pipeline is a transmission line, including operator's records, FPC/FERC certification, photograph, description by investigator, etc. 2. Documentation showing the class location for transmission line segments, including operator's records, photographs, description by investigator, etc. 3. Documentation showing whether the pipeline is at highway, waterway or railroad crossing, including operator's records (maps), photographs, description by investigator, etc. 4. Documentation showing that patrols were not made at required intervals, including operator’s records of inspection kept to show adherence to O&M plan kept pursuant to §192.603(b) and operator's record of patrol kept pursuant to §192.709. 5. Documentation showing that patrols were not made at more frequent intervals than required as determined by usual operating conditions affecting the safety and operation of the pipeline. 6. Documentation or lack thereof, including pictures that conditions existed on the pipeline ROW that may adversely affect the safety and operation of the pipeline that were not identified during the patrol. 7. Patrolling and associated follow-up records. 8. The lack of procedures and documents.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.706
Section Title	Transmission Lines – Leakage Surveys
Existing Code Language	Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted- (a) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year; and (b) In Class 4 locations, at intervals not exceeding 4 1/2 months, but at least four times each calendar year.
Origin of Code	Original Code Document, 40 FR 20283, 05-09-1975
Last Amendment	Amdt. 192-7, 59 FR 6575, 02-11-1994.
Interpretation Summaries	**Interpretation: PI-ZZ-051 Date: 04-03-2001** The DOT pipeline safety regulations at 49 CFR §192.706 and §192.723 only require that leakage be conducted "using leak detector equipment" and is not limited to the use of flame ionization. Leak detection regulations are performance based meaning that any equipment capable of detecting all leaks in gas distribution or transmission systems may be used. The regulations do not mandate the use of any specific type of detection equipment.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-01-02, Emergency Plans and Procedures for Responding to Multiple Gas Leaks and Migration of Gas Into Buildings.** Owners and operators of gas distribution systems should ensure that their emergency plans and procedures require employees who respond to gas leaks to consider the possibility of multiple leaks, to check for gas accumulation in nearby buildings, and, if necessary, to take steps to promptly stop the flow of gas. These procedures should be communicated to both employee and contractor personnel who are responsible for emergency response to pipeline incidents. **Advisory Bulletin, ADB-97-03, Potential soil subsidence on pipeline facilities.** Pipeline and Hazardous Materials Safety Administration (PHMSA) is advising operators of pipeline facilities of the need for caution associated with heavy rainfall, 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	GPTC Guide Material is available.
Guidance Information	1. The operator must have written procedures. 2. Leak detection equipment must be calibrated. 3. Records should indicate each facility surveyed, the survey date, the person who conducted the survey, and the survey result. 4. Surveys must be performed and recorded on all required Transmission Pipelines (including pipe, valves, above ground facilities and appurtenances, meter stations, etc. - including those that are off the main pipeline ROW. (See Pipeline definition under §192.3). 5. Records should indicate the survey method (vegetation, leak detector equipment, aerial, foot, etc.), and the type/model of any leak detection equipment used. 6. Inspector should compare operator's class location lists and class change records with leak survey records, to verify that any required class 3 or 4 leak detection equipment surveys are being conducted. 7. Vegetation surveys are permitted in Class 1 & 2 areas or where Class 3 & 4 areas are odorized. 8. Leak detection equipment is not required for Class 1 & 2. 9. Final Order Guidance: a. ***Brea Canon Oil Company* [5-2004-0005] (Sep. 13, 2006):** Withdrawing as moot an allegation of violation for failing to perform leak surveys of an unodorized gas gathering line that operates at less than 0 psig. *Note: Such a line would now be deemed exempt from all of the requirements in 49 C.F.R. Part 192 under 49 C.F.R. 192.1(b) (4)(i).* CO/CP
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures. 4. Required (§192.706) leak surveys, including gas detector equipment surveys on unodorized class 3 or 4 pipelines, have not been conducted. 5. Required surveys have not been conducted within the prescribed time intervals. 6. Required surveys have been inadequately conducted. 7. Leaks that were not discovered by recent surveys. 8. Leak survey equipment was not calibrated at the time the survey was performed.
Examples of Evidence	1. Leak survey records/reports. 2. Documented statements from the operator. 3. Type of leak detection equipment. 4. Leak detection equipment calibration. 5. Leak detection equipment operating manual. 6. The lack of procedures or documents.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.707
Section Title	Line Markers for Mains and Transmission Lines
Existing Code Language	(a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line: (1) At each crossing of a public road and railroad; and (2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference. (b) Exceptions for buried pipelines. Line markers are not required for the following buried pipelines: (1) Waterways and other bodies or water. (2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under §192.614. (3) Transmission lines in Class 3 or 4 locations until March 20, 1996. (4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical. (c) Pipelines above ground. Line markers must be placed and maintained along each section of a main and transmission line that is located above ground in an area accessible to the public. (d) Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker: (1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with ¼ inch (6.4 millimeters) stroke. (2) The name of the operator and telephone number (including area code) where the operator can be reached at all times.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-85, 63 FR 37504, 07-13-1998.
Interpretation Summaries	**Interpretation: PI-92-006 Date: 02-04-1992** Part 192 does not define "heavily developed urban areas." as referenced in §192.707(d)(1). All Class 4 locations - places where building four or more stories in height are prevalent - are included in the term "heavily developed urban areas." Buildings of four or more stories normally are prevalent only in such areas. The definition of "Class 3 location" does not necessarily indicate that the location is in a heavily developed urban area. Yet the definition could encompass such areas, depending on the circumstances. We consider the surroundings of a Class 3 location to decide if all or part of it is a heavily developed urban area for purposes of

§192.707(d) (1).

Interpretation: PI-91-022 Date: 07-16-1991

For the purpose of §192.707(c), we consider an area accessible to the public if entrance into the area is not physically controlled by the operator or if the area may be entered without difficulty. Based on these criteria and your description of the farm tap's location, we consider the farm tap to be located in an area accessible to the public for the following reasons:

1) the area is not under the operator's control, and
2) the area is not described as having any man-made or natural impediments to prevent public access.

The application of the regulation depends upon all factors relevant to whether an operator exercises physical control or whether an area is difficult to enter. These factors can only be ascertained by examination of the site. Two factors to consider are whether the area is adequately fenced and locked or guarded, and if not fenced, the remoteness of a facility from areas frequented by the public. These and other relevant factors should be considered by enforcement personnel in applying Section §192.707(c) to given situations.

Interpretation: PI-79-019 Date: 06-20-1979

§192.707(a) provides that each pipeline marker that is required to be installed must be "maintained". Although specific criteria for maintenance are not set forth, under this general maintenance requirement, markers must be kept free of obscuring vegetation if they are to help identify the location of pipelines, which is the purpose of §192.707.

Interpretation: PI-76-079 Date: 12-15-1976

Internal request for definition of "accessible to the public".

> The question has been placed as to what is meant by accessible to the public in the following examples of aboveground situations:
>
> (a) District regulator station located in an urban area (class 3 or 4) adjacent to a public roadway and not fenced;
>
> (b) District regulator station located in a rural area adjacent to or in close proximity to farm land or wooded areas and not fenced;
>
> (c) District regulator station located in an urban area adjacent to a public roadway and fenced but not locked;
>
> (d) District regulator station located in an urban area adjacent to a public roadway - fenced and locked.
>
> (e) Pig trap and blow down facilities located in a

<table>
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rural area (farm lands and wooded areas).

Which of the above examples require marking to meet the requirements of 192.707(c)?

Under the definitions in Section 192.3, a "regulator station" and the other facilities to which you referred are included within the meaning of "pipeline" and the terms "transmission line" and "main". Thus, these facilities must be marked if they are located aboveground in an area accessible to the public.

With regard to your question about how the term "accessible to the public" would apply to the five situations given in your memorandum, the descriptions of the situations are insufficient for us to make a determination of the application of the regulation. The application of the regulation depends upon all factors relevant to whether an operator exercises physical control or whether an area is difficult to enter. These factors can only be ascertained by examination of the site. Two factors to consider are whether the area is adequately fenced and locked or guarded, and if not fenced, the remoteness of a facility from areas frequented by the public. These and other relevant factors should be considered by enforcement personnel in applying Section 192.707(c) to given situations.

Interpretation: PI-76-058 Date: 09-13-1976

Has OPS approved a marking system related to the marking of utility lines at the site of excavation? Response: That is a requirement over and above Section 192.707 and is a matter of State or Local law.

Interpretation: PI-75-044   Date: 04-30-1975

Pipelines carrying liquefied petroleum gas, hydrogen, ammonia, or carbon dioxide in liquid form which are operated by an interstate carrier must be marked under 49 CFR 195.410. Pipelines carrying ammonia or hydrogen gas or other gas which is flammable, toxic, or corrosive must be marked under 49 CFR 192.707. Pipelines carrying carbon dioxide gas are not subject to regulation under Part 192 since carbon dioxide gas is not flammable, toxic, or corrosive.

Interpretation: PI-ZZ-014 Date: 10-07-1974

Operator identified four lines in a common trench with pipeline markers at the outside edge on each side. Does this comply with Section 192.707? Answer: Only two markers “over” four lines probably does not comply with Section 192.707.

Interpretation: PI-ZZ-010 Date: 06-06-1973

Inquiry as to whether line marker had to show direction of flow. Answer: No.

</td></tr>
<tr><td>Advisory Bulletin/Alert Notice</td><td></td></tr>
</table>

Summaries	
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. Install line markers for each transmission line 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. Waterways or bodies of water, especially those subject to dredging or commercial vessel activities. g. Fence lines, notable changes in direction, or exposed pipe including spans. 2. 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. 3. Temporary or permanent 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. 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. Projects of long duration near or on the pipeline may require more frequent verification that markers are in place (see damage prevention guidance). 6. Multiple lines in a common ROW must have markers for each pipeline located in the ROW. 7. Assure line markers have current operator name and current telephone number. 8. Verify that listed 24-hour phone number is responded to by a person who works for the pipeline operator, not just a recorder. 9. Other methods of indicating the presence of the line are adequate (such as stenciled markings, cast monument plaques, signs or other devices installed in curbs, sidewalks, streets, building facades or any other appropriate location) where the use of conventional markers are not feasible. 10. Consider where feasible to include on the line marker the Dig Safely national campaign logo and message: Call Before You Dig; Wait the Required Time for Marking; Respect the Marks; and Dig With Care. Call your local One-Call Center or the toll-free National Referral number, 1-888-258-0808. 11. All exposed pipe must have a marker, whether the pipe is intentionally or unintentionally exposed. 12. Stickers, as long as permanently affixed and fully legible must be applied may

	be applied over outdated info as soon as practicable (within six months) over outdated information: however, the telephone number must reach the pipeline operator at all times. 13. Letters on the marker should be about 1" high with ¼ inch stroke, and easily readable.
Examples of a Probable Violation	1. Buried main or transmission line is not marked at the crossing of a public road, railroad and it is practicable to do so, and no interference prevention program is established by law. 2. There are an inadequate number of line markers, operator name & phone number missing, or no markers at aboveground pipelines accessible to the public. 3. There is no marker in other areas where a marker would be necessary to reduce the possibility of damage or interference. 4. Above-ground main or transmission line in area accessible to public is not marked. 5. Markers have not been updated or do not contain required information. 6. Exposed pipe including wash-outs and spans, in areas accessible to the public, without markers. 7. The listed telephone number does not reach the pipeline operator, or their contracted service provider, at all times.
Examples of Evidence	1. Documentation showing the class location for the transmission line, including operator's records, photograph, description by investigator, etc. 2. Documentation showing whether the pipeline is at highway or railroad crossing, including operator's records (maps), photographs, description by investigator, etc. 3. Documentation showing that an above ground pipeline is not marked in an area accessible to the public, including operator's records, photograph, description by investigator, etc. 4. Documentation that it is not impractical to locate the marker, including investigator's analysis of practicability. 5. Documentation that marker does not meet requirement of §192.707(d), including color photographs and detailed investigator description of measurements and other characteristics.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.709
Section Title	Transmission Lines – Record Keeping
Existing Code Language	Each operator shall maintain the following records for transmission lines for the periods specified: (a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service. (b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section. (c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-78, 61 FR 28770, 06-06-1996
Interpretation Summaries	**Interpretation: PI-76-005 Date: 01-27-1976** Records kept by an operator prior to adoption of Federal standards must be made available to regulatory authority upon request.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. Computerized records are acceptable, if sufficient details are included. 2. Patrolling and equipment malfunction reports should generate follow-up maintenance activities and their associated records.
Examples of a Probable Violation	1. Operator did not maintain records for the required time periods. 2. Computerized records lack sufficient detail, or were not managed properly, lost, deleted or otherwise destroyed. 3. Omission of required records.
Examples of	1. Documentation that no record of the event was kept, including operator's or

Evidence	investigator's statement of absence of record. 2. Operator representative's statement regarding the missing records.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.711
Section Title	Transmission Lines – General Requirements for Repair Procedures
Existing Code Language	(a) Temporary repairs. Each operator shall take immediate temporary measures to protect the public whenever: (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and (2) It is not feasible to make a permanent repair at the time of discovery. (b) Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following: (1) Non integrity management repairs: The operator must make permanent repairs as soon as feasible. (2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O – Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by $192.933(d). (c) Welded patch. Except as provided in §192.717(b)(3), no operator may use a welded patch as a means of repair.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-114, 75 FR 48593, 08-11-2010
Interpretation Summaries	**Interpretation: PI-ZZ-037 Date: 04-15-1988** Sections 192.711 – 192.719 apply to the field repair of transmission lines. Any mechanical coupler of acceptable design and strength may be used when the use of a weldless joining device is appropriate under Sections 192.711-192.719. The acceptability of couplers is governed by various sections in subparts B, D and F of Part 192. Prior DOT approval is not required for the use of any type of gas pipeline facility, including mechanical couplers. Operators are free to select and use materials that they determine, either on their own or with the aid of manufacturers' representations, are acceptable under DOT standards. The correctness of these determinations is subject to review by DOT and State agency enforcement personnel during periodic inspection visits.

Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-09-02, Weldable Compression Coupling Installation** The Pipeline and Hazardous Materials Safety Administration (PHMSA) advises operators of hazardous liquid and natural gas pipelines installing or planning to install weldable compression couplings and similar repair devices to follow manufacturer procedures to ensure correct installation. In addition, PHMSA also advises these operators to follow the appropriate safety and start-up procedures to ensure the safety of personnel and property and protect the environment. The failure to install a weldable compression coupling correctly, or the failure to implement and follow appropriate safety and start-up procedures, could result in a catastrophic pipeline failure. PHMSA strongly urges operators to review, and incorporate where appropriate into operators' written procedures, the manufacturer's installation procedures and any other necessary safety measures for safe and reliable operation of pipeline systems. **Alert Notice ALN-87-01, Incident involving the fillet welding of a full encirclement sleeve on a 14" API 5LX-52 pipeline, 03-13-1987** 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	GPTC Guide Material is available. Pipeline Repair Manual, PRCI, August 2006
Guidance Information	1. If it is not feasible to make an immediate permanent repair at the time of discovery, then measures to ensure public safety must be taken by the operator; such as a temporary repair, lowering the operating pressure, or other measures. 2. A temporary repair does not have to be replaced with a permanent repair within a specified time period, unless the operator's procedures give specific guidance. 3. Patches are not permitted on pipe whose MAOP would produce an effective hoop stress at or above 40kips SMYS (ref. §192.717(b)(3)). 4. Associated permanent repair requirements are also addressed in §§192.713, 192.715, and 192.717.
Examples of a	1. Lack of procedures is a violation of §192.605.

Probable Violation	2. Lack of records is a violation of §192.603. 3. Operator discovered a leak, imperfection, or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40% of the SMYS, but failed to make a permanent repair as soon as feasible. 4. Operator discovered a leak, imperfection, or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of the SMYS, but failed to take immediate temporary measures to protect the public when a permanent repair was not immediately feasible 5. Operator used a patch that does not comply with §192.717(b)(3).
Examples of Evidence	1. Operator's procedures. 2. Documented statements from operator. 3. Operator's first discovery records/reports. 4. Operator's maintenance records/reports. 5. Documentation of the pipeline segments SMYS. 6. Photographs. 7. The lack of procedures and documents.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.713
Section Title	Transmission Lines – Permanent Field Repair of Imperfections and Damages
Existing Code Language	(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be- (1) Removed by cutting out and replacing a cylindrical piece of pipe; or (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. (b) Operating pressure must be at a safe level during repair operations.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-88, 64 FR 69660, 12-14-1999.
Interpretation Summaries	**Interpretation: PI-10-0013 Date: 11-18-2010** The letter asks for an interpretation of the Federal Pipeline Safety Regulations relating to pipe repairs at 49 CFR §§192.309(b), 192.485(a), 192.487(a), 192.713(a)(2) and 192.717(b)(5) and 49 CFR §195.585(a)(2). You noted that these regulations were amended in 1999 to allow alternative repair of unacceptable damages, dents, imperfections, corrosion, and leaks "by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe." Regarding the requested information from PHMSA on how the gas and hazardous liquid pipeline safety regulations address the following questions: 1. Do these regulations limit the number of discrete applications or the length of application of alternative repair systems? The regulations do not prescribe a particular limit to the number of discrete applications of an alternative repair method. The engineering test data for the material to be used must clearly demonstrate that the alternative repair method will restore the original design strength of the pipe, but will also perform in the pipeline environment in which it is installed, including withstanding secondary stresses of loading, pipe movement, soil movement, and external loads, for the length of service for which it is intended. While the 1999 rule (64 FR 69660, December 14, 1999) allows alternative repair methods for individual repairs on corroded or damaged steel pipe in natural gas pipelines or corroded steel pipe in hazardous liquid pipelines where appropriate, an operator of a pipe joint having sufficient defects should carefully consider all reliable methods of repair before installing an excessive number of alternative repairs. 2 Can alternative repair systems be used to increase the pressure capacity of a span

of pipeline above the original maximum operating pressure in response to revised operating demands?

No. The regulations require pipeline operators to repair their pipelines as necessary to maintain safety and serviceability. No repair method can be used to increase the original design strength or the pressure of a segment of pipeline above the established maximum operating pressure.

3. Can alternative repair systems be used to address the need to lower stress levels in the base pipe in response to a change in class location or other revised operating conditions?

No. A change in Class Location is not a repair issue. The stress level and maximum operating pressure of a given section of pipe is based on the original material and design specifications, not the material used to repair the pipe. Therefore, operators must continue to follow the requirements of §§192.609 and 192.611 to confirm or revise the MAOP as necessary upon a change in Class Location, regardless of whether an alternative repair method was used to perform a repair.

Interpretation: PI-91-007 Date: 03-21-1991

The letter asks about the installation of a "full encirclement welded split sleeve" under 49 CFR Part 192 Sections 192.713(a)(2) and 192.715(c). First, you asked whether the sleeve ends and pipe must be joined by circumferential fillet welds. Section 192.713(a) governs the repair of certain pipe imperfections or damage discovered in transmission lines operating above 40 percent of SMYS, and §192.715 governs the repair of certain girth weld defects discovered in any transmission line in service. Although both rules require the installation of a full encirclement welded split sleeve for certain repair situations, the rules are silent on whether the installation must include circumferential fillet welds. Such welds are required, therefore, only when necessary to accomplish the purpose of the installation.

If the imperfection or damage or girth weld defect is not leaking and may not reasonably be expected to leak, the purpose of installing a full encirclement welded split sleeve is to bolster the strength of the pipeline in the vicinity of the imperfection or damage or girth weld defect. This purpose can be accomplished without welding the sleeve ends to the pipe; so circumferential fillet welds are not required. However, if the imperfection or damage or girth weld defect is leaking or may reasonably be expected to leak, the purpose of the full encirclement welded split sleeve is not only to bolster the strength of the pipeline, but also to stop the present or possible future leak. In this case, either circumferential fillet welds or other suitable means must be used to permanently seal the sleeve ends and contain the pipeline pressure. Circumferential fillet welds would be required only if the other means available would not accomplish that purpose.

Next you asked if the two half shells that form the full encirclement welded split sleeve must be joined by welding or may they be joined mechanically. Under §§192.713(a)(2) and 192.715(c), in the phrase "full encirclement welded split sleeve," the term "welded" modifies the term "split sleeve." The meaning of the combined terms is that the two half shells must be joined by welding. In contrast,

	§192.713(b) expressly allows submerged pipelines to be repaired by mechanically joining the two half shells of a full encirclement split sleeve. Note that in §192.713(b) the term "welded" does not appear in the phrase "full encirclement split sleeve." **Interpretation: PI-ZZ-037 Date: 04-15-1988** The letter asks whether mechanical couplers fall under Sections 192.711 – 192.719 of the Federal Gas Pipeline safety Standards (49CFR part 192), and whether the Department of Transportation (DOT) must approve your company's product before it may be used in gas pipelines. Sections 192.711 – 192.719 apply to the field repair of transmission lines. Any mechanical coupler of acceptable design and strength may be used when the use of a weld less joining device is appropriate under Sections 192.711-192.719. The acceptability of couplers is governed by various sections in subparts B, D and F of part 192. Prior DOT approval is not required for the use of any type of gas pipeline facility, including mechanical couplers. Operators are free to select and use materials that they determine, either on their own or with the aid of manufacturers' representations, are acceptable under DOT standards. The correctness of these determinations is subject to review by DOT and State agency enforcement personnel during periodic inspection visits.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-09-02, Weldable Compression Coupling Installation** The Pipeline and Hazardous Materials Safety Administration (PHMSA) advises operators of hazardous liquid and natural gas pipelines installing or planning to install weldable compression couplings and similar repair devices to follow manufacturer procedures to ensure correct installation. In addition, PHMSA also advises these operators to follow the appropriate safety and start-up procedures to ensure the safety of personnel and property and protect the environment. The failure to install a weldable compression coupling correctly, or the failure to implement and follow appropriate safety and start-up procedures, could result in a catastrophic pipeline failure. PHMSA strongly urges operators to review, and incorporate where appropriate into operators' written procedures, the manufacturer's installation procedures and any other necessary safety measures for safe and reliable operation of pipeline systems. **Alert Notice ALN-87-01, Incident involving the fillet welding of a full encirclement repair sleeve on a 14" API 5LX-52 pipeline, 03-13-1987** 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	GPTC Guide Material is available. Pipeline Repair Manual, PRCI, August, 2006. Mechanical Damage Final Report, TTO 16, Michael Baker Jr. Inc (http://primis.phmsa.dot.gov/gasimp/docs/MECHANICAL_DAMAGE_FINAL_REPORT.pdf AGA Pipeline Research Committee Project PR3-805 (RSTRENG) API Standard 1104, ''Welding of Pipelines and Related Facilities'' (20th edition, October 2005, errata/addendum, (July 2007) and errata 2 (2008)).
Guidance Information	1. The operator must have written field repair procedures. 2. Guidelines for timeframes for repairs in "covered segments" can be found in the Gas Integrity Management rule, 192 Subpart O. 3. The repair method selected must be able to "permanently restore the serviceability of the pipe," with a result comparable to that expected from replacing damaged pipe or installing a full-encirclement split sleeve. §192.717(b)(5). 4. Such restoration is considered permanent if the repair is expected to last as long as the pipe under normal operating and maintenance conditions. 5. The repair method must have undergone "reliable engineering tests and analyses." §192.717(b)(5). 6. The repair method must be compatible with environmental conditions and potential fire and other safety hazards. 7. Appropriate NDT assessment should be performed in conjunction with repairs (§192.241, §192.719). 8. UT examination of the repair area should be performed immediately prior to the intended repair work to assure safe working conditions. 9. Repairs requiring welding must be performed under a specific qualified welding procedure and with qualified welders.- If the pipeline is to be repaired while the pipeline is in service, consideration must be made for maintaining a safe operating pressure.

Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written field repair procedures. 4. The procedure is too general to provide adequate guidance or establish specific requirements for the task being performed. 5. The procedure simply repeats the regulation. 6. Operator failed to properly remove/repair an imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40% of SMYS. 7. Repairs requiring welding were made r without a specific qualified welding procedure or with unqualified welders. 8. Use of composite pipe wrap type repair for permanent repair of defects, imperfections or damages of pipe not supported by engineering test and analysis.
Examples of Evidence	1. Operator's procedures. 2. Documented operator's statements. 3. Operator's maintenance records/reports. 4. Engineering assessments and analysis. 5. The lack of procedures and documents.
Other Special Notations	1. Consideration should be given to the use of low hydrogen welding for in- service pipeline repairs.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.715
Section Title	Transmission Lines – Permanent Field Repair of Welds
Existing Code Language	Each weld that is unacceptable under §192.241(c) must be repaired as follows: (a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of §192.245. (b) A weld may be repaired in accordance with §192.245 while the segment of transmission line is in service if: (1) The weld is not leaking (2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and (3) Grinding of the defective area can be limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains (c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-85, 63 FR 37504, 07-13-1998.
Interpretation Summaries	**Interpretation: PI-91-007 Date: 03-21-1991** The letter asked about the installation of a "full encirclement welded split sleeve" under 49 CFR 192.713(a)(2) and 192.715(c). First, you asked whether the sleeve ends and pipe must be joined by circumferential fillet welds. Section §192.713(a) governs the repair of certain pipe imperfections or damage discovered in transmission lines operating above 40 percent SMYS and §192.715 governs the repair of certain girth weld defects discovered in any transmission line in service. Although both rules require the installation of a full encirclement welded split sleeve for certain repair situations, the rules are silent on whether the installation must include circumferential fillet welds. Such welds are required, therefore, only when necessary to accomplish the purpose of the installation. If the imperfection or damage or girth weld defect is not leaking and may not reasonably be expected to leak, the purpose of installing a full encirclement welded split sleeve is to bolster the strength of the pipeline in the vicinity of the imperfection or damage or girth weld defect. The purpose can be accomplished without welding the sleeve ends to the pipe; so circumferential fillet welds are not required. However, if the imperfection or damage or girth weld defect is leaking or may reasonable be expected to leak, the purpose of the full encirclement welded split sleeve is not only to bolster the strength of the pipeline, but also to stop the

present or possible future leak. In this case, either circumferential fillet welds or other suitable means must be used to permanently seal the sleeve ends and contain the pipeline pressure. Circumferential fillet welds would be required only if the other means available would not accomplish that purpose.

Next you asked if the two half shells that form the full encirclement welded split sleeve must be joined by welding or may be join mechanically. Under §§192.713(a)(2) and 192.715(c), in the phrase "full encirclement welded split sleeve" the term "welded" modifies the term "split sleeve". The meaning of the combined terms is that the two half shells must be joined by welding. In contrast, §192.713(b) expressly allows submerged pipelines to be repaired by mechanically joining the two half shells of a full encirclement sleeve. Note that in §192.713(b) the term "welded" does not appear in the phrase "full encirclement split sleeve".

Interpretation: PI-ZZ-037 Date: 04-15-1988

Following is the response to whether mechanical couplers fall under Sections 192.711 – 192.719 of the Federal Gas Pipeline safety Standards (49CFR part 192), and whether the Department of Transportation (DOT) must approve your company's product before it may be used in gas pipelines.

Sections 192.711 – 192.719 apply to the field repair of transmission lines. Any mechanical coupler of acceptable design and strength may be used when the use of a weld less joining device is appropriate under Sections 192.711-192.719. The acceptability of couplers is governed by various sections in subparts B, D and F of part 192.

Prior DOT approval is not required for the use of any type of gas pipeline facility, including mechanical couplers. Operators are free to select and use materials that they determine, either on their own or with the aid of manufacturers' representations, are acceptable under DOT standards. The correctness of these determinations is subject to review by DOT and State agency enforcement personnel during periodic inspection visits.

Interpretation: PI-84-007 Date: 11-09-1984

Question:

§192.245(c) requires that repair of a girth weld containing a crack be made in accordance with qualified written weld repair procedures.

§192.715(c) allows for the repair of a defective weld by installing a full encirclement welded split sleeve of appropriate design if the weld cannot be repaired in accordance with §§192.715(a) or (b).

If an operator, in repairing a dresser coupled pipeline made that repair by removing a section of pipe and welding in a new section of pipe, determined that there was a crack in one of the tie-in welds, could he satisfy the requirements of the regulations by installing a full encirclement welded split sleeve? Keep in mind that this is a

	dresser coupled pipeline, or contains dresser couplings, and the joints could have been made by using dresser couplings in the first place. Could this same type of repair be made if the pipeline were a welded line? What circumstances could warrant the weld "not repairable" by the criteria of §§192.715(a) or (b)? For the above situations, assume the operator is not interested in establishing and qualifying procedures for repair of cracks and repair of previously repaired areas. Answer: Your first two paragraphs generally paraphrase the intent and meaning of §§192.245(c) and 192.715(c) to the extent you state them, except that §192.715(c) requires the repair of a defective weld with a sleeve rather than "allows" it if it "cannot be repaired in accordance with paragraph (a) or (b). The problem you present arises because of inappropriate application of §192.715 which is for the permanent field repair of welds in the maintenance of an existing line. It is not a "construction" requirement. When the operator repairs the Dresser coupled pipeline by "removing a section of pipe and welding in a new section" all applicable sections of Subpart E must be complied with in "replacement" of that section by welding, including §192.245. Repair of the "crack in one of the tie-in welds" must be in accordance with §192.245, and it would not be permissible to install "a full encirclement welded split sleeve" for such a repair. After the operator elected to repair the pipe by replacement of a welded tie-in section, the fact that the original pipeline was Dresser coupled is irrelevant. The repair method you hypothesized is not appropriate for a replacement section in a "welded line" for the same reasons that it was not for the Dresser coupled one. Requirements of §192.715(0 and (b) appear to be clear and specific and if they cannot be met in the permanent field repair of welds in the maintenance of an existing pipeline, then paragraph (c) "must be" met. Circumstances in which paragraph (c) would apply would include those where it is not feasible to take the transmission line out of service and the conditions of paragraph (b) cannot be met (e.g., defective weld is leaking). When the operator decides to repair the pipeline by "replacement" of a section, it does not enjoy the prerogative of being "not interested in establishing and qualifying procedures for repair of cracks" in the tie-in welds it must perform.
Advisory Bulletin/Alert Notice 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. **Advisory Bulletin ADB-09-02, Weldable Compression Coupling Installation** The Pipeline and Hazardous Materials Safety Administration (PHMSA) advises operators of hazardous liquid and natural gas pipelines installing or planning to install weldable compression couplings and similar repair devices to follow manufacturer procedures to ensure correct installation. In addition, PHMSA also advises these operators to follow the appropriate safety and start-up procedures to ensure the safety of personnel and property and protect the environment. The failure to install a weldable compression coupling correctly, or the failure to implement and follow appropriate safety and start-up procedures, could result in a catastrophic pipeline failure. PHMSA strongly urges operators to review, and incorporate where appropriate into operators' written procedures, the manufacturer's installation procedures and any other necessary safety measures for safe and reliable operation of pipeline systems. **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	GPTC Guide Material is available. API Standard 1104, ‘‘Welding of Pipelines and Related Facilities’’ (20th edition, October 2005, errata/addendum, (July 2007) and errata 2 (2008)).

	Pipeline Repair Manual, PRCI, August, 2006.
Guidance Information	1. The operator must have written procedures. 2. Some weld defects during initial construction as listed in API-1104, Section 9, can be repaired once in the same physical location on the weld, using the same welding procedure as was used to make the original weld. 3. A weld area can be repaired only one time with the original welding procedure. Multiple repairs are permissible as long as they are not in the same location on the weld. 4. A weld that has already been repaired at a specific location can be repaired again at that location with a separate qualified welding repair procedure. The repaired area is only a small portion of the total weld. Therefore, the qualification of this procedure is treated as a fillet weld, and only four straps are required from the repaired area to test and qualify the repair procedure. 5. Other code requirements are addressed in §192.245. 6. Direct deposit welding requires a specific welding procedure and welder qualification.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written field repair procedures. 4. Making more than one repair to a weld in the same area without a specific welding repair procedure. 5. A repaired weld did not meet the requirements of API-1104, Section 9. 6. Making a repair to a weld with the pipeline operating above 20% SMYS.
Examples of Evidence	1. Photographs of repaired weld, if still exposed. 2. Records associated with the repairs. 3. Copies of NDT evaluations. 4. Copies of the welding procedure. 5. Qualification records used to establish the welding procedure. 6. The lack of procedures or records.
Other Special Notations	Consideration should be given to the use of low hydrogen welding for in- service pipeline repairs.

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.717
Section Title	Transmission Lines – Permanent Field Repair of Leaks
Existing Code Language	Each permanent field repair of a leak on a transmission line must be made by- (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or (b) Repairing the leak by one of the following methods: (1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS. (2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp. (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size. (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design. (5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
Origin of Code	Original Code Document, 35 FR 13248, 08-17-1970
Last Amendment	Amdt. 192-88, 64 FR 69665, 12-14-1999
Interpretation Summaries	**Interpretation: PI-10-0013 Date: 11-18-2010** The letter asks for an interpretation of the Federal Pipeline Safety Regulations relating to pipe repairs at 49 CFR §§192.309(b), 192.485(a), 192.487(a), 192.713(a)(2) and 192.717(b)(5) and 49 CFR §195.585(a)(2). You noted that these regulations were amended in 1999 to allow alternative repair of unacceptable damages, dents, imperfections, corrosion, and leaks "by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe." Regarding the requested information from PHMSA on how the gas and hazardous liquid pipeline safety regulations address the following questions: 1. Do these regulations limit the number of discrete applications or the length of application of alternative repair systems? The regulations do not prescribe a particular limit to the number of discrete applications of an alternative repair method. The engineering test data for the material to be used must clearly demonstrate that the alternative repair method will restore the original design strength of the pipe, but will also perform in the pipeline environment in which it

is installed, including withstanding secondary stresses of loading, pipe movement, soil movement, and external loads, for the length of service for which it is intended. While the 1999 rule (64 FR 69660, December 14, 1999) allows alternative repair methods for individual repairs on corroded or damaged steel pipe in natural gas pipelines or corroded steel pipe in hazardous liquid pipelines where appropriate, an operator of a pipe joint having sufficient defects should carefully consider all reliable methods of repair before installing an excessive number of alternative repairs.

2. Can alternative repair systems be used to increase the pressure capacity of a span of pipeline above the original maximum operating pressure in response to revised operating demands?

No. The regulations require pipeline operators to repair their pipelines as necessary to maintain safety and serviceability. No repair method can be used to increase the original design strength or the pressure of a segment of pipeline above the established maximum operating pressure.

3. Can alternative repair systems be used to address the need to lower stress levels in the base pipe in response to a change in class location or other revised operating conditions?

No. A change in Class Location is not a repair issue. The stress level and maximum operating pressure of a given section of pipe is based on the original material and design specifications, not the material used to repair the pipe. Therefore, operators must continue to follow the requirements of §§192.609 and 192.611 to confirm or revise the MAOP as necessary upon a change in Class Location, regardless of whether an alternative repair method was used to perform a repair.

Interpretation: PI-ZZ-037 Date: 04-15-1988

Following is the response to whether mechanical couplers fall under Sections 192.711 – 192.719 of the Federal Gas Pipeline safety Standards (49CFR part 192), and whether the Department of Transportation (DOT) must approve your company's product before it may be used in gas pipelines.

Sections 192.711 – 192.719 apply to the field repair of transmission lines. Any mechanical coupler of acceptable design and strength may be used when the use of a weld less joining device is appropriate under Sections 192.711-192.719. The acceptability of couplers is governed by various sections in subparts B, D and F of Part 192.

Prior DOT approval is not required for the use of any type of gas pipeline facility, including mechanical couplers. Operators are free to select and use materials that they determine, either on their own or with the aid of manufacturers' representations, are acceptable under DOT standards. The correctness of these determinations is subject to review by DOT and State agency enforcement personnel during periodic inspection visits.

	Interpretation: PI-ZZ-009 Date: 04-30-1973 A sketch of a domed, contoured welding cap used to cover a pit hole clamp was enclosed with the letter. The cap is field welded for permanency on pipe of not more than 40,000 psi. SMYS. You ask, in effect, whether the design of this cap is governed by the standards of §192.717(c). As here relevant, §192.717(c) is applicable to welded steel plates that are used to repair corrosion pits. However, the cap described in the sketch appears to be a fitting or component rather than a plate. The provisions of §192.717(c) would therefore not apply to your cap. Although the regulations contained in Part 192 do not purport to cover the specific design requirements of every type of component or fitting that might be safely welded onto a pipeline, they do, however, set forth general design requirements for pipeline components including components fabricated by welding. Thus Subpart D of Part 192, including in particular §192.153, would be applicable to the design of the welding cap. Subpart E of Part 192, covering the welding of steel in pipelines, would also have general applicability with reference to the design of welding caps. To the extent that you consider your welding cap to be a branch connection as suggested in your letter, the applicable design requirement is set forth in §192.155. That requirement is stated as a performance standard rather than a detailed specification, and the means of compliance is left with the designer. **Interpretation: PI-ZZ-007 Date: 02-09-1973** Following is the response to your letter asking whether bolted split sleeves rather than welded split sleeves may be used in certain repairs on transmission lines in view of the requirements stated in Sections 192.717 and 192.153(b)(4). Although your letter states that Section 192.717 requires a welded split sleeve, a recent amendment to that section (Amendment 192-12 issued October 11, 1972) now provides an exception. Thus, if the repair is to be made on a transmission line joined by mechanical couplings and operated at less than 40 percent of SMYS, use of a bolted split sleeve would be acceptable under the amended requirement. Your letter asks whether your bolted split sleeves might be used for repair under the provision of Section 192.153(b) (4), since you test them to twice working pressure. The requirements of Section 192.153(b) (4), however are applicable to the design of pipeline components whereas Section 193.717 applies to the permanent field repair of leaks on transmission lines. Thus Section 192.153(b)(4) does not provide an exception from the repair requirements of Section 192.717.
Advisory Bulletin/Alert Notice	**Advisory Bulletin ADB-09-02, Weldable Compression Coupling Installation**

Summaries	The Pipeline and Hazardous Materials Safety Administration (PHMSA) advises operators of hazardous liquid and natural gas pipelines installing or planning to install weldable compression couplings and similar repair devices to follow manufacturer procedures to ensure correct installation. In addition, PHMSA also advises these operators to follow the appropriate safety and start-up procedures to ensure the safety of personnel and property and protect the environment. The failure to install a weldable compression coupling correctly, or the failure to implement and follow appropriate safety and start-up procedures, could result in a catastrophic pipeline failure. PHMSA strongly urges operators to review, and incorporate where appropriate into operators' written procedures, the manufacturer's installation procedures and any other necessary safety measures for safe and reliable operation of pipeline systems. **Alert Notice ALN 87-01, Incident involving the fillet welding of a full encirclement repair sleeve on a 14" 5LX-52 pipeline.** 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	GPTC Guide Material is available. Pipeline Repair Manual, PRCI, August, 2006.
Guidance Information	1. The operator must have written procedures. 2. If the pipeline is to be repaired without taking it out of service, the operating pressure must be reduced to a safe level during the repair process. 3. Determination of the safe operating pressure during the repair is left up to the operator, through their application of pre-established guidance material. 4. Appropriate UT examination of the repair area should be performed to insure the integrity of the planned repair.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written field repair procedures. 4. The procedure is too general to provide adequate guidance or establish specific requirements for the task being performed. 5. The procedure simply repeats the regulation. 6. The MAOP of the replacement cylinder is not commensurate with §192.619. 7. Patch installed on the pipe that has a yield of 40,000 psi or more (§192.717(b)(3)).

Examples of Evidence	1. Photographs of the pipe prior to the repair. 2. Photographs of the repair. 3. Copies of documents that describe the repairs made to the pipeline. 4. Documentation of the pipe specifications. 5. The lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.719
Section Title	Transmission Lines – Testing of Repairs
Existing Code Language	(a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed. (b) Testing of repairs made by welding. Each repair made by welding in accordance with §§192.713, 192.715, and 192.717 must be examined in accordance with §192.241.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-54, 51 FR 41635, 11-18-1986.
Interpretation Summaries	**Interpretation: PI-94-024 Date: 06-07-1994** Question #2: "Our second question relates to the hydrostatic testing of replacement pipe under §192.719(a). In a repair situation where several joints of pipe are welded together, does the welded piece have to be hydrostatically tested as a unit? Each joint is pre-tested and the welds are 100% non-destructively tested." Answer #2: Section 192.719(a) is intended for testing of repairs of transmission pipelines, where the pipe is required to be tested as a new line. The test requirements in Subpart J are applicable to a new segment of pipeline, or the return to service of a segment of pipeline that has been relocated or replaced. In accordance with §192.503(a) in Subpart J, the entire replaced segment must be tested in accordance with Subpart J and §192.619, except the tie-in joints that are excepted under §192.503(d). It should be noted that the joints connecting the several pipe lengths are not tie-in joints. However, if, in accordance with §192.505(e), it is not practical to conduct a post installation test, a preinstallation strength test must be conducted on each pipe length or the segment by maintaining the pressure at or above the test pressure for at least 4 hours. **Interpretation: PI-ZZ-037 Date: 04-15-1988** Your letter asks whether mechanical couplers fall under Sections 192.711 – 192.719 of the Federal Gas Pipeline safety Standards (49CFR part 192), and whether the Department of Transportation (DOT) must approve your company's product before it may be used in gas pipelines. Sections 192.711 – 192.719 apply to the field repair of transmission lines. Any

	mechanical coupler of acceptable design and strength may be used when the use of a weld less joining device is appropriate under Sections 192.711-192.719. The acceptability of couplers is governed by various sections in subparts B, D and F of Part 192. Prior DOT approval is not required for the use of any type of gas pipeline facility, including mechanical couplers. Operators are free to select and use materials that they determine, either on their own or with the aid of manufacturers' representations, are acceptable under DOT standards. The correctness of these determinations is subject to review by DOT and State agency enforcement personnel during periodic inspection visits.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. The operator must have written procedures for the testing of repairs. 2. Appropriate UT examination of the repair area should be performed to insure the integrity of the planned repair. 3. A pipe segment that is replaced must be pressure tested after installation unless it is not practical, in which case each length of pipe or each segment must be pressure tested. 4. Special attention should be applied to the potential for stresses associated with out-of-roundness, high-low, alignment, and changes in pipe wall or grade. 5. Records documenting pretest of pipe for emergency use must include an audit trail to each specific joint of pipe installed in the pipeline.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures for testing of repairs. 4. Test records for installed pipe cannot be traced back to the original test documentation. 5. NDT records are not available concerning inspection of welds made on repair fittings and devices.
Examples of Evidence	1. Records regarding the repairs made to the pipeline. 2. Statements from supervisory personnel regarding any missing or incomplete records. 3. Metallurgical reports. 4. Incident reports. 5. The lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.727
Section Title	Abandonment or Deactivation of Facilities
Existing Code Language	(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section. (b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard. (c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard. (d) Whenever service to a customer is discontinued, one of the following must be complied with: (1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. (2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly. (3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed. (e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging. (f) Each abandoned vault must be filled with a suitable compacted material. (g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. (1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at http://www.npms.phmsa.dot.gov or contact the NPMS National Repository at 703-317-6294. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety,

	Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington DC 20590-0001; fax (202) 366-4566; e-mail, *InformationResourcesManager*@PHMSA.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-109, 74 FR 2894, 01-16-2009
Interpretation Summaries	**Interpretation: PI-83-019 Date: 10-31-1983** Responding to your use of the expandable polymer plug process for permanent abandonment of a service line. The method would satisfy the requirements of §192.727(d)(2) whenever service to a customer is discontinued. However, use of a plug device without disconnecting the service from the source of gas would not meet the requirements of §192.727(b). **Interpretation: PI-ZZ-026 Date: 01-29-1982** Section 192.725(a) states, in part, that "each disconnected service line must be tested in the same manner as a new service line, before being reinstated." What is the meaning of "disconnect" as used in Section 192.725(a)? A "disconnected" service line is a service line that has been physically -separated from a main and does not include a service line that remains physically connected to the main, or has been taken out of service by closing a valve between the main and service line. **Interpretation: PI-ZZ-027 Date: 01-19-1982** We recognize the potential for harm when customer stop valves can be reopened by an impatient customer following a service outage. Nevertheless, it is our opinion that the protective measures called for by §192.727(d) were not intended to apply to temporary interruptions of gas flow that do not involve termination of service to a customer. In making this interpretation, we were constrained by the record of the original proceeding (docket no. OPS-10), and our reading of that record does not lead us to conclude that §192.727(d) was intended to cover all situations in which a customer's stop valve is closed. **Interpretation PI-81-020 Date: 12-15-1981** The letter of November 24, 1981 asks whether the steps required of an operator by §192.727(d) when service to a customer is discontinued would apply in situations such as emergency shutdown or planned maintenance where a service line is temporarily deactivated.

Discontinuance of service to the customer means that a service line is "not currently being used to provide gas service," and it does not mean "temporary closure for some purpose other than termination of service to the customer." Thus, "discontinuance" implies the customer will no longer be provided gas. A brief lapse in gas delivery, as during an outage, would not indicate an intent to "discontinue" service within the meaning of §192.727(d).

Interpretation PI-81-018 Date: 10-07-1981

A stop valve at a customer meter is closed by the customer or by someone other than the operator. The operator is not told of the closing or requested to discontinue service, but discovers at a later date that the valve is closed. After discovering the closed valve, does the operator have to meet the requirements of §192.727(d) regarding a discontinued service?

Section 192.727(d) prescribes precautionary steps an operator must take "whenever service to a customer is discontinued." This regulation was established to prevent accidents caused by the unauthorized reactivation of service lines that are not currently being used to provide gas service. The potential for such accidents arises when the delivery of gas to a customer is discontinued. The potential is the same whether discontinuance results from an action by the operator or by someone else. Thus the operator would have to comply with §192.727(d) if the closed stop valve represented a discontinuance of service, even though the valve was closed without the operator's knowledge. Whether the closed valve amounted to a discontinuance of service, and not just a prank or temporary closure for some purpose other than termination of service to the customer, would depend on facts that should have been ascertained by the operator after discovering the closed valve.

Interpretation PI-79-044 Date: 12-14-1979

The letter asks if the use of a wire seal on a closed service line valve constitutes a "locking device or other means designed to prevent the operating of the valve by persons other than those authorized by the operator," as envisioned by Section 192.727, Abandonment or inactivation of facilities, paragraph(d)(1), and if it does not, what does?

A wire seal or any other type of locking device that can be removed or made ineffective by using ordinary household tools such as a screwdriver or pliers would not prevent the opening of such a service line valve by persons other than those authorized by the operator. Therefore, a wire seal would not meet the requirements of Section 192.727(d)(1).

Interpretation PI-78-025 Date: 10-11-1978

The letter states your position that Section 192.727(d) does not apply when a responsible party requests that service be transferred to their name with no actual

	discontinuance. Your interpretation of this part for this type of situation is correct. The situation you describe is in the nature of an accounting procedure whereby customers are changed for billing purposes but discontinuance of gas service to the premises is not affected. Premises is meant to mean the individual house, apartment, place of business, etc., involved and not necessarily the entire building. The letter also asks whether this regulation applies in a situation where an interim period exists when gas service is not requested by another party. In this type of situation, the provisions of §192.727(d) do apply. **Interpretation PI-72-056 Date: 12-26-1972** Section 192.727 of the Federal natural gas pipeline safety regulations (49 CFR Part 192) allows inactivation of pipelines by use of a valve that is equipped with a locking device or other means designed to prevent its unauthorized opening. The use of a lock on the meter set valve would meet the requirements of Section 192.727(d)(1) and is, therefore, acceptable. However, the cutting off of gas by a valve in curb-box, as the sole means for disconnecting a customer, is not satisfactory. Also note that the same standards apply to new service lines not placed in service upon completion of installation under the provisions of new §192.379(a). **Interpretation: PI-72-050 Date: 11-10-1972** Under the amendment, Sections 192.379(d) and 192.727(d)(2) now provide for the inactivation of lines by use of a mechanical device or fitting installed in the service line or in the meter assembly to prevent the flow of gas. One practice is to valve off the service cock, break the meter inlet connection, and insert a tin shut off seal in order to prevent unauthorized use of gas. The use of a shut off seal or disc is a commonly used method to prevent the flow of gas, and the procedure described in the letter is one of the methods we had in mind in adopting this alternative method in the amendment.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-08-07, National Pipeline Mapping System** Notifies operators of gas transmission pipelines, hazardous liquid pipelines, and LNG plant operators of voluntary changes in submittal of NPMS data. Beginning January, 2009 PHMSA is requesting submittal of gas transmission and hazardous liquid NPMS information concurrent with the submittal of annual reports. **Advisory Bulletin ADB-03-02, Pipeline Safety: Required Submission of Data to the National Pipeline Mapping System Under the Pipeline Safety Improvement Act of 2002.** The Office of Pipeline Safety (OPS) is issuing this advisory bulletin to owners and operators of natural gas transmission and hazardous liquid pipeline systems. The purpose of this bulletin is to advise pipeline operators of their responsibilities in complying with the Pipeline Safety Improvement Act of 2002. Specifically, this

	bulletin indicates the process for making new submissions of geodetical and operator contact information, updating previous submissions to the National Pipeline Mapping System (NPMS), and providing future submissions. After June 17, 2003, operators must make submissions every 12 months if any system modifications have occurred. If no system modifications have occurred, the operator must submit an e-mail stating that fact.
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. An abandoned pipeline must be physically isolated from active pipelines, disconnected from all sources of gas, purged of gas, and sealed at both ends. 2. An inactive pipeline, which may or may not contain gas, must meet all of the requirements of Part 192. 3. The operator must have written procedures for abandoning a facility. 4. Operators sometimes do not completely abandon a pipeline and may sometimes use terms such as "idle" or "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 192.
Examples of a Probable Violation	1. The lack of a procedure is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow their written procedure for abandoning a facility. 4. An abandoned section of pipeline was not disconnected from sources and supplies of gas, purged of gas, and/or sealed at both ends. 5. Service to a customer was discontinued and its connection was not locked, blind flanged, or otherwise separated. 6. An offshore pipeline was abandoned in place and was not disconnected from all sources and supplies of gas; purged of gas; filled with water or inert materials, or sealed at the ends. 7. The operator did not file a report to PHMSA-NPMS for each abandoned offshore or onshore facility over, under or through a commercially navigable waterway, as required by §192.727(g). 8. Operator did not file an updated annual filing as part ADB-03-02 to the National Pipeline Mapping System (NPMS).

Examples of Evidence	1. Documentation/Photos/Statements that show the operator did not disconnect the abandoned pipeline from all sources and supplies of gas, and purged of gas. 2. Operator did not fill an abandoned offshore pipeline with water or inert materials; and sealed at the ends. 3. If air is used for purging, documentation showing that operator did not insure that a combustible mixture was not present after purging. 4. Documentation/Photos/Statements that shows an abandoned vault was not filled with a suitable compacted material. 5. NPMS output showing an abandoned pipeline is still considered active. 6. Operator's written procedure. 7. The lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.731
Section Title	Compressor Stations – Inspection and Testing of Relief Devices
Existing Code Language	(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §192.739 and §192.743, and must be operated periodically to determine that it opens at the correct set pressure. (b) Any defective or inadequate equipment found must be promptly repaired or replaced. (c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-43, 47 FR 46851, 10-21-1982
Interpretation Summaries	**Interpretation: PI-ZZ-048 Date: 02-08-1999** Regarding whether 49 CFR Part 192 Sections 192.731, 192.739, and 192.743 apply to compressor station relief devices that relieve natural gas in equipment and systems associated with operation of the compressor, such as fuel gas lines and instrument gas lines, PHMSA previously stated that these sections apply to all gas relief devices in compressor stations. Only relief devices on non-gas carrying equipment are exempt. **Interpretation: PI-79-018 Date: 06-01-1979** The word "pressure" in §§192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. The sections do not apply to devices or regulators which are part of non-gas carrying equipment that may exist inside gas compressor stations. This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of §192.195 for installation of pressure control devices. **Interpretation: PI-79-005 Date: 03-12-1979** I am forwarding a copy of a letter written by Marshall W. Taylor, Chief of the Central Region, Office of Pipeline Safety, interpreting the above referenced sections of Title 49, Code of Federal Regulations. In his letter Mr. Taylor states that "the requirements of §§192.731, 192.739 and 192.743 do not apply to relief devices or regulators which are not installed in a piping system or storage vessels containing gas . . ." **Interpretation: PI-77-005 Date: 01-28-1977**

	The letter asks whether the requirements of Sections 192.731, 192.739, and 192.743 concerning the maintenance of pressure relief devices and limiting stations apply to devices and stations which are not part of a "pipeline" as that term is defined in Section 192.3. As examples, you refer to devices and regulators which are used in gas compressor stations for purposes other than to relieve or limit gas pressure, such as devices or regulators on compressed air or fuel systems. The word "pressure" in Sections 192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. The sections do not apply to devices or regulators which are part of non-gas carrying equipment inside gas compressor stations. This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of Section 192.192 for installation of pressure control devices. Since under Section 192.3 the term "pipeline" encompasses all the gas carrying parts of an operator's systems, the pressure relief devices and limiting stations subject to Sections 192.731, 192.739, and 192.743 are those on a pipeline.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. Testing and inspection of all devices is required to be performed at least once each calendar year, not to exceed 15 months, as per §192.739(a). 2. Determination of set pressure should be derived from both MAOP and SMYS considerations, see §§192.739 and 192.743 for further guidance. Additionally, if the pipeline is operating under a special permit or corrective action order, see special permit or order requirements. 3. Testing methods should not create an over-pressure condition. 4. Set pressures for primary pressure regulating or control devices must be set to prevent the system from being normally operated above the MAOP. 5. If there is no automatic pressure regulating or control device that prevents a pipeline from being normally operated above the MAOP then pressure relief devices associated with that system should not be set above the MAOP of the pipeline being protected. 6. Factors affecting the calculation of capacity can be derived from manufacturer data and/or direct measurement during full flow conditions. 7. Calculated capacity must include the effect of piping size and length associated with the relief device. Relief valve outlet piping and vent stack should be included in capacity calculations. 8. The device capacity should be based on the largest single upstream pressure regulating or pressure control device failure that may occur.

	9. If calculations or determination otherwise indicates that capacity is not adequate, adjustments shall be made promptly. 10. Relief valve vent stack protected from elements, dirt, and debris? Rain cap installed and functioning. 11. During annual testing, at least one remote control shutdown device must be used to activate the facility shutdown utilities; however, actual gas blow-down is not required. 12. All individual remote control shutdown devices must be inspected and tested to verify that they each can activate the facility shutdown utilities. Any other system that is used to activate the ESD needs to be inspected and tested under this section. 13. If the operator's procedure specifies a blowdown time, the operator must have documentation that the test verifies that blowdown time can be met 14. The operator must have a site specific written procedure for conducting ESD tests. 15. Connectivity and calibration between unit trip sensors and its associated unit control panel should be verified during testing. 16. Unit trips within the station may be the primary means of over-pressure protection; and may work with redundant or secondary reliefs to achieve or enhance station blow-down. 17. If check valves are used to provide station isolation during blow-down, the operator must verify the integrity of the seal on the check valves. 18. Conventional and check valves used as a part of the remote control shutdown (ESD) system must be inspected and tested to verify effective seals for pressure isolation on an annual basis . 19. A compressor station must have overpressure devices unless it was constructed prior to March 12, 1971 and has not had any modifications. 20. All equipment found to be defective or inadequate during these inspections and tests must be promptly repaired or replaced. 21. Regulators and overpressure protection devices on compressor fuel gas or instrumentation gas lines are subject to the requirements of §§192.731, 192.739, and 192.743. 22. The operator must have written procedures for inspecting and testing relief and other overpressure protection devices. These procedures must include that any component that can inhibit the operation of the ESD should be locked out.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures for inspection and testing relief valves. 4. A remote control shutdown device is not inspected and tested within the required intervals. 5. The review of the required capacity, the inspection, or the testing of the relief device is not made within the required intervals. 6. Actual relief or unit trip pressures do not match required settings and prompt remedial action was not taken. 7. Capacity calculations do not match the current station piping design. 8. Changes to the station required that relief capacity needed to be greater, but no changes were incorporated in a timely manner.

	9. Equipment inspection reports indicate that a valve used for isolation (ESD) and blowdown was noted as in need of maintenance; however, the valve was not repaired promptly. 10. Inspection reports for pressure control/pressure relief devices indicate that repairs were required but those repairs have not been made promptly. 11. Regulators and over pressure protection devices on compressor fuel gas and instrumentation gas have not been tested and inspected at the required intervals. 12. A pressure limiting device that has a set point set above the limits allowed under §192.739. 13. A pressure limiting device that fails to operate at the set point which then leads to an incident. 14. The operator did not have, or follow, their written procedures. 15. Rupture discs are not appropriate for the required application. 16. The operator did not have documentation of their inspections or tests. 17. Any component that could inhibit the operation of ESD was not isolated e.g., valves in front of relief valves. 18. Blow down stacks not properly protected from elements, dirt, or debris. 19. A compressor station does not have the appropriate relief devices. 20. The operator did not perform a test of the ESD within the required time frame.
Examples of Evidence	1. Operator(s) listing of station ESD valves and controlling devices. 2. Pressure control/pressure relief inspection and test records, or ESD inspection and test records. 3. Photographs. 4. Documentation of increased compressor flow rates. 5. Capacity calculation sheets. 6. MAOP listings. 7. Pressure charts or pressure database records. 8. Station shutdown reports. 9. Trip device inspection records. 10. Station schematics. 11. Rupture disc documentation 12. Operator’s written procedures. 13. The lack of procedures or documents.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.735
Section Title	Compressor Stations – Storage of Combustible Materials
Existing Code Language	(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building. (b) Above ground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	None
Interpretation Summaries	**Interpretation: PI-ZZ-065 Date: 07-02-1998** Under §192.735(a) "flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building". For §192.735(a) to apply to compressor lubricating oil, the oil must be flammable or combustible. Although neither term is defined in Part 192, the ordinary meaning of flammable or combustible is to catch fire readily or burn easily. The information you furnished shows that compressor lubricating oil is hard to ignite, and is not flammable or combustible based on the ordinary meaning. You also pointed out that compressor lubricating oil does not qualify as a flammable or combustible liquid under the more specific definitions in RSPA's hazardous material regulations (49 CFR 173.120(a) and (b)) or in ANSI/NFPA 30, "Flammable and Combustible Liquids Code" (paragraphs 1-7.3.1 and 1-7.3.2). Therefore, we conclude that compressor lubrication oil is not covered by §192.735(a).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NFPA 30 (2008 edition, August 15, 2007), ''Flammable and Combustible Liquids Code'' (2008 edition; approved August 15, 2007)
Guidance Information	1. NFPA 30 Section 4 covers Tank Storage. Below are some of the citing listed in that section: a. NFPA 30 Section 4.2.9 requires that protected tanks be listed and tested in accordance with UL 2085, Standard for Protected Aboveground Tanks for Flammable and Combustible Liquids. This section also requires that these tanks meet both of the following requirements: i. Construction that provides the required fire-resistive protection that

	reduces the heat transferred to the primary tank and prevents release of liquid, failure of the primary tank, failure of the supporting structure, and impairment of venting for a period of not less than 2 hours when tested using the fire exposure specified in UL 2085. ii. The size of the emergency vent cannot be reduced, as would otherwise be permitted by NFPA 30 Section 4.2.5.2.6. b. NFPA Section 4.3.1 Foundations for and Anchoring of Tanks. c. NFPA Section 4.3.1.1 requires these tanks rest on the ground or on foundations made of concrete, masonry, piling, or steel. This section also requires that tank foundations be designed to minimize the possibility of uneven settling of the tank and to minimize corrosion in any part of the tank resting on the foundation. d. NFPA Section 4.3.1.2 requires that where tanks are supported above their foundations, the tank supports be installed on firm foundations. This section also requires that supports for tanks storing Class I, Class II, or Class IIIA liquids be made of concrete, masonry, or protected steel. However there is an exception that allows single wood timber supports (not cribbing), that are laid horizontally to support outside aboveground tanks if not more than 0.3 m (12 in.) high at their lowest point. e. The tables given in NFPA 30 Section 4.3.2 list minimum distances tanks must be from important buildings depending on the hazards and the hazard classification of the liquids stored. f. NFPA Section 4.3.2.2 gives shell to shell spacing for aboveground tanks depending on the hazards and the hazard classification of the liquids stored. g. NFPA Section 4.3.2.3 requires the operator to control spills from aboveground tanks that contain Class I, Class II, or Class IIIA liquids with a means to prevent an accidental release of liquid from endangering important facilities and adjoining property or from reaching waterways. The control measures must meet the requirements of NFPA Sections 4.3.2.3.1, 4.3.2.3.2, or 4.3.2.3.3, whichever is applicable. 2. Combustible materials such as paint, solvents, etc need to be stored in an explosion proof cabinet within the compressor building. 3. Wooden pallets, cardboard boxes, or other combustible items cannot be stored or located in compressor building.
Examples of a Probable Violation	1. Combustible materials such as paint, solvents, etc are not stored in an explosion proof cabinet within the compressor building. 2. Wooden pallets, cardboard boxes, or other combustible items stored or located in compressor building.
Examples of Evidence	1. Photos of paint cans, or other solvents other than those in current use are stored in the compressor building. 2. Photos of combustible material such as cardboard boxes, wooden pallets, etc are stored in a compressor building.
Other Special	

Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.736
Section Title	Compressor Stations – Gas Detection
Existing Code Language	(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is- (1) Constructed so that at least 50 percent of its upright side area is permanently open; or (2) Located in an unattended field compressor station of 1,000 horsepower (746 kilowatts) or less. (b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must- (1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and (2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger. (c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.
Origin of Code	Original Code Document, 58 FR 48460, 09-16-1993
Last Amendment	Amdt. 192-85, 63 FR 37500, 07 13-1998
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available. GPTC Guide Material for §192.171
Guidance Information	1. Since the noise level in active stations may be high, a visual indication (i.e. strobe) may be necessary to alert those within the building. 2. A warning system must be designed using sound engineering practices taking into account background noise and lighting at the site. The system must be able to warn persons inside or outside the building of the presence of not more than 25% LEL concentration of gas. 3. Since gas detectors are normally mounted high in the building, special testing techniques may need to be applied to ensure the system will activate at 25% LEL. 4. The operator shall have written procedures for inspection and testing of gas

	detectors including establishing inspection intervals. Consideration should be given to manufacturer's recommendations and site specific factors for establishing the inspection interval. 5. The operator should maintain records to demonstrate satisfactory testing in a reasonable interval. 6. The gas detection alarm signal should be unique from other facility alarms. 7. Station shutdown or blow-down is not required on the occurrence of a 25% LEL gas detection alarm; however, the operator's procedures must address investigating and/or eliminating the cause of the alarm.- Gas detectors should be mounted in places where gas is likely to accumulate inside the building. 8. Having an alarm only in the control room is insufficient. 9. The gas detection system must be properly calibrated.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures. 4. Gas detection threshold is greater than 25% LEL. 5. The warning system is ineffective in notifying personnel inside or outside the building of the presence of gas. 6. There is no warning system inside or outside of the building. 7. Gas detectors are not mounted in places where gas may accumulate inside the building. 8. Gas detection and alarm system did not function properly. 9. Operator did not perform testing in accordance with the operator's prescribed testing interval 10. Repairs were not made promptly. 11. The gas detection system was not properly calibrated. 12. The operator's procedure for testing the gas detection system does not specify a testing interval.
Examples of Evidence	1. Inspection and test records, including threshold settings. 2. Photographs showing the location of detector installation. 3. The brightness of the strobe or volume of audible alarms is insufficient. 4. Incident reports. 5. Documented statements from operator personnel. 6. Operator's procedures. 7. The lack of procedures or records.
Other Special Notations	

<table>
<tr><td>Enforcement Guidance</td><td>O&M Part 192</td></tr>
<tr><td>Revision Date</td><td>12-07-2011</td></tr>
<tr><td>Code Section</td><td>§192.739</td></tr>
<tr><td>Section Title</td><td>Pressure Limiting and Regulating Stations – Inspection and Testing</td></tr>
<tr><td>Existing Code Language</td><td>(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is-
(1) In good mechanical condition;
(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;
(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressures consistent with the pressure limits of §192.201(a); and
(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.
(b) For steel pipelines whose MAOP is determined under §192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

<table>
<tr><td>If the MAOP produces a hoop stress that is:</td><td>Then the pressure limit is:</td></tr>
<tr><td>Greater than 72 percent of SMYS.</td><td>MAOP plus 4 percent.</td></tr>
<tr><td>Unknown as a percentage of SMYS.</td><td>A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.</td></tr>
</table>
</td></tr>
<tr><td>Origin of Code</td><td>Original Code Document, 35 FR 13248, 08-19-1970</td></tr>
<tr><td>Last Amendment</td><td>Amdt. 192-96, 69 FR 27861, 05-17-2004</td></tr>
<tr><td>Interpretation Summaries</td><td>Interpretation: PI-ZZ-056 Date: 01-22-2004

Responding to a request for an interpretation of the Federal gas pipeline safety regulation at 49 CFR 192.739, Pressure Limiting and Regulating Stations: Inspections and Testing regarding small regulators on the system that provide protection for operating, or end-use, equipment. These types of regulators are installed by the manufacturer of the equipment.

Section 192.701, Scope, notes the Subpart M "prescribes minimum requirements for maintenance of pipeline facilities." Section 192.739 must be read in cognizance of this scope statement. It is clear that §192.739 is intended to address inspection and testing of pressure limiting and regulating stations that are necessary to maintain safe pressures on the pipeline facility, not on end-use equipment.</td></tr>
</table>

This is consistent with the June 28, 1988, interpretation letter cited in your letter. In that interpretation, we note that a regulator subject to §192.739 would have to fall within the definition of "pressure limiting station" or "pressure regulatory station" as these terms are defined in the ASME B31.8 standard. Under these definitions, it is clear that any regulator serving a downstream piping is a pressure regulating station and is subject to inspection and testing in accordance with §192.739. Conversely, a regulator that is NOT intended to protect a downstream piping, but rather serves only to protect end-use equipment, such as a compressor, would not be subject to §192.739.

Interpretation: PI-ZZ-048 Date: 02-08-1999

Following is the response to whether 49 CFR Part 192 Sections 192.731, 192.739, and 192.743 apply to compressor station relief devices that relieve natural gas in equipment and systems associated with operation of the compressor, such as fuel gas lines and instrument gas lines, PHMSA previously stated that these sections apply to all gas relief devices in compressor stations. Only relief devices on non-gas carrying equipment are exempt.

Interpretation: PI-93-019 Date: 04-28-1993

This letter is to further clarify my letter of October 22, 1992, in which I tried to clarify the specific inspections and tests the operator should be required to conduct in complying with §192.739. I explained in that letter that regulator stations must be inspected and tested to comply with §192.739 using any practicable method that will demonstrate compliance with paragraphs (a) through (d) of §192.739. Set-point, lock-up, and full-stroke-operation would be part of the inspection and testing if such tests are practicable at the station concerned.

Regulator stations that use service-type regulators, such as stations that supply master meter systems, may not be equipped with valving, manifolding, or by-passes. This equipment is needed to preclude interruption of supply to a customer or group of customers while maintenance is performed. Consequently, all the inspections and tests that can be done at some regulator stations may not be practicable at stations with service-type regulators.

In addition, to us, practicable inspections and tests do not require the operator to disassemble the regulator, re-pipe the regulator, or cut off the supply of gas to the system. Instead, we suggest that, as a minimum, these service-type regulators be visually inspected, be checked for leaks (including the regulator vent), and be checked for correct set-point. Verifying the correct set-point on a service-type regulator can be done by measuring the pressure of the gas (downstream of the regulator) with a pressure gauge. (We plan to better define "regulator station" in a future rulemaking).

Interpretation: PI-92-058 Date: 10-22-1992

In response to a drawing submitted of two distribution systems with regulator stations, since the only difference in the two distribution systems you portray is the size of the operator, the two systems are subject to the same inspection and test requirements.

You request that we identify specific inspections and tests the operator would be required by §192.739 to conduct. Specifically, you asked if set-point, lock-up, and full-stroke operation are part of the required inspections and tests.
Set-point, lock-up, and full-stroke are undefined in Part 192 and are not specified as necessary for compliance with §192.739. Section 192.739 requires all pressure limiting and regulating stations to be subjected, at intervals not exceeding 15 months, but at least one each calendar year, to inspections and tests to determine if the station has the qualities listed in paragraphs (a)-(d) of §192.739.

Regulator stations must be inspected and tested to comply with §192.739 using any practicable method that will demonstrate the presence or absence of the listed qualities. Set-point, lock-up, and full-stroke-operation would be part of the inspection and testing if such tests are practicable at the station concerned. If not, whatever other tests are practicable in meeting the requirements of §192.739 must be used. Specific procedures should be documented in the utility's operating and maintenance plan prescribed by §192.605.

Interpretation: PI-88-002 Date: 06-28-1988

The letter asks our opinion whether the Texas Railroad Commission is correct in its interpretation that the inspection and testing requirements of §192.739 apply to a pressure regulator designed in accordance with §192.197 that supplies gas to a master meter system.

For such a regulator to be subject to §192.739, it would have to come within the meaning of "pressure limiting station" or "pressure regulating station." These two terms are not defined in Part 192. However, they are defined in two widely accepted Industry documents, the ANSI B31.8 Code and the ASME Guide for Gas Transmission and Distribution Piping Systems. Under these industry definitions of a "pressure regulating station," it is clear that any regulator serving a downstream main is a pressure regulating station. While the drafters of the industry definition may not have had in mind regulators that serve mains in master meter systems, such regulators do meet the terms of the definition. Also, they function similarly to other regulators that are generally recognized to come under the definition. Thus, we support the Texas Railroad Commission's position that §192.739 applies to pressure regulator when they are used to supply gas to master meter systems.

Interpretation: PI-ZZ-036 Date: 08-31-1984

Concerning the application of 49 CFR Part 192, §192.739, Pressure limiting and regulating stations: Inspection and testing, and §192.743, Pressure limiting and regulating stations: Testing of relief devices, to metering and pressure regulating equipment used to deliver gas to a single commercial or industrial consumer.
I am enclosing a copy of Interpretation 81-1, dated March 17, 1981. This

interpretation makes it clear that these maintenance requirements (§§192.739 and 192.743) do not apply to regulator installations on service lines.

Interpretation: PI-81-006 Date: 03-17-1981

QUESTION#1: Are the pressure regulating and relief installations described in §192.197(c) subject to the requirements of §192.739?

ANSWER: The pressure regulating and relief installations described in §192.197 for high pressure distribution systems are those for a service line with meter and service regulator and series regulator, service regulator or other protective devices.

QUESTION #2: The requirements of §192.739 are for regulating stations such as a city gate measuring and pressure regulating station or a distribution regulator station installed in a gas distribution main regulating a multiple feed distribution system.

ANSWER: Since the pressure regulating and relief devices described in §192.197 are neither a city gate measuring and pressure regulating station nor a distribution regulating station regulating a multiple feed distribution system, they are not subject to the inspection and testing requirements of §192.739.

Interpretation: PI-79-018 Date: 06-01-1979

The word "pressure" in §§192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. The sections do not apply to devices or regulators which are part of non-gas carrying equipment that may exist inside gas compressor stations. This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of §192.195 for installation of pressure control devices.

Interpretation: PI-79-005 Date: 03-12-1979

Pursuant to our conversation of this afternoon, I am forwarding a copy of a letter written by Marshall W. Taylor, Chief of the Central Region, Office of Pipeline Safety, interpreting the above referenced sections of Title 49, Code of Federal Regulations. In his letter Mr. Taylor states that "the requirements of §§192.731, 192.739 and 192.743 do not apply to relief devices or regulators which are not installed in a piping system or storage vessels containing gas . . ."

Interpretation: PI-77-005 Date: 01-28-1977

The letter asks whether the requirements of Sections 192.731, 192.739, and 192.743 concerning the maintenance of pressure relief devices and limiting stations apply to devices and stations which are not part of a "pipeline" as that term is defined in Section 192.3. As examples, you refer to devices and regulators which are used in gas compressor stations for purposes other than to relieve or limit gas pressure, such as devices or regulators on compressed air or fuel systems.

The word "pressure" in Sections 192.731, 192.739, and 192.743 restricts the

<table>
<tr><td></td><td>applicability of those sections to devices or stations which serve to relieve or limit gas pressure. The sections do not apply to devices or regulators which are part of non-gas carrying equipment inside gas compressor stations.

This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of Section 192.192 for installation of pressure control devices. Since under Section 192.3 the term "pipeline" encompasses all the gas carrying parts of an operator's systems, the pressure relief devices and limiting stations subject to Sections 192.731, 192.739, and 192.743 are those on a pipeline.

Interpretation: PI-76-066 Date: 10-04-1976

To provide for safe operation of pipelines, the maintenance requirements of §§192.739 and 192.743 apply to all relief devices on a pipeline whether or not their installation is required by §192.195. This unrestricted application is indicated by §192.703 which provides - "No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart."

Interpretation: PI-76-007 Date: 01-30-1976

<u>The letter asks whether</u> any remedial action implied in §192.739 and §192.749? If so, would such action be subject to Sections 192.195 thru 192.203 and 192.183 thru 192.189, since this would involve a change after November 12, 1970? Sections 192.739 and 192.749 govern the maintenance of pressure limiting station relief devices and pressure regulating stations and vaults used in the transportation of gas. Remedial actions as appropriate, is implicit in the requirements of these sections. Any specific component which is replaced, relocated, or changed as a result of inspections or tests made under Sections 192.739 and 192.749 must comply with all applicable requirements of 49 CFR 192, including those to which you refer.</td></tr>
<tr><td>Advisory Bulletin/Alert Notice Summaries</td><td></td></tr>
<tr><td>Other Reference Material & Source</td><td>GPTC Guide Material is available.</td></tr>
<tr><td>Guidance Information</td><td>1. Also see §192.743 guidance for capacity guidance.
2. Set pressures for pressure protection/relief devices must be set so as to prevent system pressures from exceeding the pressure limits of either §192.201(a) or §192.739(b), whichever is applicable. See below.

<table>
<tr><td>If the MAOP:</td><td>Then the pressure limit is:</td></tr>
<tr><td>Produces a hoop stress equal to or less than 72% of SMYS and is 60 psig or greater.</td><td>The lower of…
MAOP plus 10 percent or
75% SMYS.</td></tr>
<tr><td>Produces a hoop stress equal to or less</td><td>MAOP plus 6 psig.</td></tr>
</table></td></tr>
</table>

than 72% of SMYS and is 12 psig or more, but less than 60 psig.	
Produces a hoop stress equal to or less than 72% of SMYS and is less than 12 psig.	MAOP plus 50 percent.
Was determined under §192.619(c) and produces a hoop stress greater than 72% of SMYS .*	MAOP plus 4 percent.
Was determined under §192.619(c) and produces a hoop stress that is unknown as a percentage of SMYS.*	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

* This does not apply to pipelines operating under 192.620 alternate SMYS.

3. Visually check station piping supports, control/sensing/supply lines, and ventilating equipment for proper design and maintenance.
4. If a pipeline was either built or modified after March 12, 1971 and the pressure limiting device is removed from service for testing; adequate over-pressure protection of the affected line must still be maintained.
5. Device testing records shall include the set pressure of the device as well as the name of the individual who did the testing.
6. Testing relief valves to determine they are in good mechanical condition requires, in part, physical movement of the valve plug to assure the valve can open.
7. Relief stacks must be free of obstructions and have rain caps or weep holes.
8. Relief stacks, as well as instrument supply line vents, must be above the roof line.
9. Check valves may not be used as pressure control devices.
10. The occurrence of over-pressure may be indicative of an equipment failure or design flaw. Overpressure should be documented as an abnormal operation as per §192.605 (c)(1)(ii) Operation of the relief device should also be documented as an abnormal operation as per §192.605 (c)(1)(iv).
11. Facilities not in service, but still physically connected, must meet the inspection and testing requirements of §192.739.
12. Regulators and over pressure protection devices on compressor fuel gas lines and instrumentation gas are subject to the requirements of §§192.731, 192.739, and 192.743.
13. §192.195(a) indicates that except for relief valves and rupture disks, two devices are required for overpressure protection "Except as provided in §192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices……..."

14. For a pipeline or pipeline facility that was either built or modified after March 12, 1971 the downstream pressure rating of a regulator must be capable of withstanding pressures it would be subjected to if it were to fail open. §192.143.
15. If a facility has been installed or modified after March 12, 1971, and there is only a single pressure control device, the operator must also be able to show that

	the failure of that device will not cause the downstream MAOP to be exceeded, otherwise there must be an over-pressure protection device installed that will meet the requirements of §192.199 and §192.201. 16. If the regulator assembly includes a worker/monitor configuration, then separate taps and sensing lines are required; or designed to fail-safe. §192.199. 17. Facilities either built or modified after March 12, 1971 are required to meet the requirements of §192.201(a): Setpoints can either be locally or remotely controlled or set; however, sole reliance on remote human intervention to activate a safety valve in the case of regulator or pressure control failure does not satisfy the set point requirements of §192.201(a). 18. Devices such as pressure switches or transducers that are used as overpressure protection, must meet the requirements of annual testing, and be set at the appropriate points. 19. Slam shut valves or other fail close devices are acceptable overpressure protection. 20. The operator must have written pressure limiting and regulating stations inspection and testing procedures.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written inspection and testing procedures. 4. Excessive ice buildup on the downstream side of a regulating station that impedes the operation of any pressure protection device. 5. Inadequate or non-existent overpressure protection equipment for §192.195(a that may allow the MAOP to be exceeded as a result of pressure control or other type of failure. 6. Test or review of the required capacity of the relief device is not made within the required intervals. 7. Inspection and testing of an overpressure protection device has not been completed within the required intervals. 8. Actual set pressures do not match required settings. 9. Capacity calculations do not match the current station piping design. Capacity calculations should include downstream piping capacity calculations for maximum pressure and flow. 10. Changes to a station relief capacity were not made after a facility change or operation change that required an increase in relief capacity. 11. The operator did not change setpoints when MAOP changed. 12. Repairs to pressure control/pressure relief devices to correct an unsafe condition were not made prior to resuming operations. 13. Regulators and over pressure protection devices on compressor fuel gas and instrumentation gas have not been tested and inspected at the required intervals. 14. A pressure limiting device that has a set point set above the pressure limits allowed. 15. A pressure limiting device that fails to operate at the set point due to lack of maintenance. 16. Unremediated corrosion or mechanical damage of the device or associated control piping. 17. Capacity calculations that pre-date piping changes (or other factors) that may have impacted actual capacity requirements.

	18. Unprotected relief ports that would be subject to damage or restriction from water, ice, debris, etc. 19. A facility built or modified after March 12, 1971 has out of service tests conducted without an equivalent temporary device or adequate manual control provided to protect against the possibility of over-pressure. 20. Except for relief valves, only one overpressure protection device. 21. Unintended operation of a relief device not documented as an abnormal operation. 22. Check valves are used as overpressure protection.
Examples of Evidence	1. Test records. 2. Photographs. 3. Station schematics. 4. Documentation of increased upstream regulator capacity. 5. Capacity calculation sheets. 6. MAOP listings. 7. Maintenance records. 8. Stations pressure charts or database pressure history. 9. Incident reports. 10. Operator’s written procedures. 11. Equipment and manufacturer’s specifications. 12. The lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.743
Section Title	Pressure Limiting and Regulating Stations – Capacity of Relief Devices
Existing Code Language	(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a. This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations. (b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient. (c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-96, 69 FR 27861, 05-17-2004
Interpretation Summaries	**Interpretation: PI-ZZ-048 Date: 02-08-1999** Following is the response to whether 49 CFR Part 192 Sections 192.731, 192.739, and 192.743 apply to compressor station relief devices that relieve natural gas in equipment and systems associated with operation of the compressor, such as fuel gas lines and instrument gas lines, PHMSA previously stated that these sections apply to all gas relief devices in compressor stations. Only relief devices on non-gas carrying equipment are exempt. **Interpretation: PI-92-034 Date: 07-23-1992** If an operator seeks to satisfy the requirements of over-pressure protection by relying on over-pressure devices of others, the operator is still responsible for compliance with §192.743. If an operator maintains a pressure limiting or regulating station that was built before March 12, 1971 that was not designed with over-pressure protection devices, and has not been changed or modified since that time, then the operator is not required to install over-pressure protection at that station, unless §192.619(b) applies. **Interpretation: PI-ZZ-036 Date: 08-31-1984**

Concerning the application of 49 CFR Part 192, Sections 192.739, Pressure limiting and regulating stations: Inspection and testing, and 192.743, Pressure limiting and regulating stations: Testing of relief devices, to metering and pressure regulating equipment used to deliver gas to a single commercial or industrial consumer.

Interpretation 81-1, dated March 17, 1981 makes it clear that these maintenance requirements (§§192.739 and 192.743) do not apply to regulator installations on service lines.

Interpretation: PI-81-006 Date: 03-17-1981

QUESTION #2. Are the relief devices described in §192.197(c)(1) and (3) subject to the requirements of §192.743?

ANSWER: For the same reasons given in the answer to question #1, the relief devices described in §192.197(c)(1) and (3) would not be subject to the testing requirements of §192.743.

Interpretation: PI-79-018 Date: 06-01-1979

The word "pressure" in §§192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. The sections do not apply to devices or regulators which are part of non-gas carrying equipment that may exist inside gas compressor stations. This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of §192.195 for installation of pressure control devices.

Interpretation: PI-79-005 Date: 03-12-1979

I am forwarding a copy of a letter written by Marshall W. Taylor, Chief of the Central Region, Office of Pipeline Safety, interpreting the above referenced sections of Title 49, Code of Federal Regulations. In his letter Mr. Taylor states that "the requirements of §192.731, §192.739 and §192.743 do not apply to relief devices or regulators which are not installed in a piping system or storage vessels containing gas . . ."

Interpretation: PI-77-005 Date: 01-28-1977

Following is the response to whether the requirements of Sections 192.731, 192.739, and 192.743 concerning the maintenance of pressure relief devices and limiting stations apply to devices and stations which are not part of a "pipeline" as that term is defined in Section 192.3. As examples, you refer to devices and regulators which are used in gas compressor stations for purposes other than to relieve or limit gas pressure, such as devices or regulators on compressed air or fuel systems.

The word "pressure" in Sections 192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. The sections do not apply to devices or regulators which are part of non-gas carrying equipment inside gas compressor stations.

This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of Section 192.192 for installation of pressure control devices. Since under Section 192.3 the term "pipeline" encompasses all the gas carrying parts of an operator's systems, the pressure relief devices and limiting stations subject to Sections 192.731, 192.739, and 192.743 are those on a pipeline.

Interpretation: PI-76-075 Date: 12-07-1976

Your memo of August 2, 1976, asks whether the maintenance requirements of §192.739 apply to pressure relief devices on a gas pipeline which are voluntarily installed by an operator at locations where relief devices are not required by §192.195.

To provide for safe operation of pipelines, the maintenance requirements of §§192.739 and 182.743 apply to all relief devices on a pipeline whether or not their installation is required by §192.195. This unrestricted application is indicated by §192.703 which provides:

"No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart."

If §§192.739 and 192.743 were only intended to apply to relief devices which are required by §192.195, then the maintenance requirements would not apply to pipelines in existence when the requirements were adopted, a result contrary to the intent of Congress as set forth in Sec. 3 of the Natural Gas Pipeline Safety Act of 1968.

Interpretation: PI-76-066 Date: 10-04-1976

To provide for safe operation of pipelines, the maintenance requirements of §§192.739 and 192.743 apply to all relief devices on a pipeline whether or not their installation is required by §192.195. This unrestricted application is indicated by §192.703 which provides - "No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart."

Interpretation: PI-76-007 Date: 01-30-1976

The letter asks whether any remedial action implied in §192.739 and §192.749? If so, would such action be subject to Sections 192.195 thru 192.203 and 192.183 thru 192.189, since this would involve a change after November 12, 1970? Sections 192.739 and 192.749 govern the maintenance of pressure limiting station relief devices and pressure regulating stations and vaults used in the transportation of gas. Remedial actions as appropriate, is implicit in the requirements of these sections. Any specific component which is replaced, relocated, or changed as a result of inspections or tests made under Sections 192.739 and 192.749 must comply with all applicable requirements of 49 CFR 192, including those to which you refer.

	Interpretation: PI-ZZ-018 Date: 09-29-1975 This responds to your letter which proposes a correction notice to be used as clarification and information to the public regarding the Office of Pipeline Safety Operations' (OPSO) Contract Study DOT-OS-3000S, “Rapid Shutdown of Failed Pipeline Systems and Limiting of Pressure to Prevent Pipeline Failure Due to Overpressure,” and its effect on Part 192, Sections 192.621(b) and 192.743(c). Conclusions, opinions, or statements made in reports on contract studies performed for OPSO are those of the contractor and do not necessarily state the position of OPSO. OPSO reviews and evaluates these reports and takes action as appropriate. As you stated in your memorandum, dated May 22, 1974, to all gas operators in the State of Arizona, the grandfather clause is not applicable to the subject sections. A statement in your memorandum that "…old stations that are protected by the grandfather clause be reviewed in light of present day standards and that these stations be replaced with up-to-date stations as money and time permits …” can be considered as advisory only. Also, in regard to part of paragraph four of the subject memorandum which states "… that changing size or adding a new or additional relief valve (or monitor regulator) was to be classed as maintenance and not new construction, therefore the station did not require entire rebuilding to new code," OPSO would like to call your attention to Section 192.199(g),of the regulations which requires that overpressure-protection devices and pressure-limiting devices be designed and installed to prevent any single incident such as explosion in a vault or damage by a vehicle from affecting the operation of both.. However, the intent of the subject section is separate pressure-limiting devices and overpressure-protection devices by distance, barrier, or separate housing, but the subject interpretation does not rule out other solutions that may be just as good as or better than the mentioned method of separating by distance, barrier, or separate housing. In other words, any new addition of pressure relief or limiting device to these existing facilities must comply with the subject section of the regulation. **Interpretation: PI-ZZ-002 Date: 12-09-1970** An internal relief type pressure regulator carries the same requirements as a pressure relief device? Regarding under what operating conditions and applications must an internal relief type pressure regulator needs to be tested for proper internal relief function, the word “feasibility” is used in its ordinary dictionary definition.
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. Also see guidance for §192.739. 2. When testing capacity in place, venting gas should not create the potential for a hazardous condition (i.e. static discharge from overhead electrical lines, accumulation of gas in a building) (see §§192.201 and 192.751). 3. Testing shall not create an abnormal operation or other unsafe condition. 4. If pressure other than MAOP is used for capacity calculation of over-pressure protective devices, there must be specific procedures in place to address the effect of changes in operating pressure on the effective relief capacity. 5. Set points and capacities of back-up or secondary over-pressure safety devices do not have to meet the code requirements, but the devices must be tested for functionality on an annual basis, not to exceed 15 months. 6. Regulators and over pressure protection devices on compressor fuel gas lines are subject to the requirements of §§192.731, 192.739, and 192.743. 7. Factors affecting the calculation of capacity can be derived from manufacturer data, direct measurement during full flow conditions and/or industry models. 8. Relief valve piping (inlet and outlet) and vent stack should be addressed in capacity calculations. 9. Capacity checks can be determined from historical engineering calculations, as long as no changes have been made to the facility's MAOP or operating parameters. 10. The device capacity should be based on the largest single upstream pressure control failure that may occur. 11. If calculations or determination otherwise indicates that capacity is not adequate, adjustments must be made promptly (see §192.703(b)). 12. If a station built before March 12, 1971, that has no over-pressure protection devices, is modified; then over-pressure protection devices must be added. 13. The operator must have written procedures for calculating capacity and verification.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures for calculating capacity and verification. 4. Test or review of the required capacity of the relief device is not made within required intervals. 5. Capacity calculations pre-date piping changes (or other factors) that may have impacted actual capacity requirements. 6. Out of service tests, conducted without an equivalent temporary device or adequate manual control to protect against the possibility of over-pressure. 7. Build up due to stack piping and/or the relief itself is not taken into consideration during capacity calculation.

Examples of Evidence	1. Photographs. 2. Capacity calculation sheets. 3. MAOP listings. 4. Pressure charts or pressure database records. 5. Manufacturer data sheets. 6. Schematics. 7. Operator's procedures. 8. The lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.745
Section Title	Valve Maintenance: Transmission Lines
Existing Code Language	(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year. (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-93, 68 FR 53895, 09-15-2003
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-02-03, Gas and Hazardous Liquid Pipeline Mapping.** This bulletin is issued 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. **Alert Notice, ALN-89-02, Results of OPS-conducted investigation of San Bernardino, CA, 05-12-89 train derailment; each gas/liquid operator should test check valves.** Alerting each gas transmission and hazardous liquid operator of the need to test check valves located in critical areas to assure that they close properly.
Other Reference Material & Source	GPTC Guide Material is available.
Guidance Information	1. The operator must identify the valves on the pipeline system that need to be operated during an emergency situation. 2. The operator must establish, and periodically review, a master list of emergency valves. 3. ESD valves are emergency valves, although they may be shown on a separate

	list and tested and inspected as part of the ESD system. 4. The operator must have written procedures for emergency valves. 5. Operator must inspect and partially operate all emergency valves within the required time intervals of §192.745. 6. Operator should use specific valve manufacturer's recommendations to develop an appropriate maintenance program. 7. Maintenance discrepancies identified during valve inspections must be addressed and remedial actions documented. 8. Valves should be identified with a number or tag, which should also be referenced on the appropriate maps. 9. Facilities installed or modified after March 12, 1971 should be protected from tampering and damage (§192.179(b)(1)). 10. Remotely operated valves must be partially operated. 11. Regulated gathering lines may have emergency valves that are outside of the regulated area. These valves must be included on the emergency valve list. 12. Examples of emergency valves may include: valves that are part of emergency shutdown in a compressor station; mainline valves for regulatory spacing requirements; side tap valves to isolate laterals or interconnects; blowdown valves; crossover valves; storage well side gate valves; valves that isolate stations; an inlet or outlet to measurement or regulator station. 13. Slam shuts, check valves, and other devices used as emergency valves must be inspected per the requirements of this part.
Examples of a Probable Violation	1. Valves required to operate during an emergency were not included on the emergency valve list. 2. Operator did not inspect or partially operate some or all of the valves on the emergency valve list. 3. The operator(s) inspection interval for some or all valves was longer than required in §192.745. 4. A valve did not operate during a field inspection. 5. Valves not properly identified with a tag or number. 6. Valves not secure and protected from tampering. 7. Operator did not adequately define "partial operation" of valve in procedures. 8. The operator did not have, or follow, written procedures for inspecting and operating emergency valves. 9. When an emergency valve became inoperable, and it could not be repaired promptly, the operator did not designate an alternative valve.
Examples of Evidence	1. Emergency valve list. 2. Pipeline schematics. 3. Station drawings. 4. ESD records. 5. Operator(s) O&M procedures. 6. Documented statements from the Operator. 7. Photographs. 8. Manufacturer's valve documentation. 9. Valve maintenance and inspection records. 10. Valve repair records.

Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.749
Section Title	Vault Maintenance
Existing Code Language	(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated. (b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired. (c) The ventilating equipment must also be inspected to determine that it is functioning properly. (d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	Amdt. 192-85, 63 FR 37500, 07-13-1998
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available. The 1994 MOA between OSHA and DOT. Letter to the head of the Virginia Commission regarding vaults.
Guidance Information	1. Only relates to vaults containing pressure regulating or pressure limiting equipment. Does not apply to vaults containing other equipment. 2. The operator must have written procedures for accessing and inspecting vaults.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures for inspecting vaults. 4. Inspection of the vault is not made in the required intervals. 5. The operator did not repair leaks that were found. 6. The vault ventilation equipment is not functioning properly. 7. The vault cover presented a hazard to public safety, such as no locking device to

	prevent unauthorized access to the vault.
Examples of Evidence	1. Operator written procedures. 2. Inspection records. 3. Repair procedures. 4. Repair records. 5. Photographs. 6. Vault physical dimensions. 7. The lack of procedures or records.
Other Special Notations	

Enforcement Guidance	O&M Part 192
Revision Date	12-07-2011
Code Section	§192.751
Section Title	Prevention of Accidental Ignition
Existing Code Language	Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following: (a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided (b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work (c) Post warning signs, where appropriate
Origin of Code	Original Code Document, 35 FR 13248, 08-19-1970
Last Amendment	
Interpretation Summaries	**Interpretation: PI-ZZ-043 Date: 05-17-1993** The following response is regarding whether the Occupational Safety and Health Administration (OSHA) had taken action in response to our letter of March 30, 1988, wherein we requested that OSHA abstain from issuing rules on certain pipeline safety operations. OSHA issued final regulations (54 FR 45894; October 31, 1989) notwithstanding our letter. However, OSHA later issued a letter of interpretation to their field offices determining that OSHA regulations in 29 CFR §§1926.651(g) (1) (iii) and 1926.651(g)(2)(i) are preempted by our pipeline safety standards. The interpretation ensued from a settlement agreement between OSHA and the American Gas Association following a petition filed in the U. S. Court of Appeals for the District of Columbia (Case No. 89-1764). A copy of the settlement agreement is enclosed. **Interpretation: PI-ZZ-044 Date: 05-17-1993** Subsection 1926.651(g)(1)(iii) of the OSHA excavation standard requires that the concentration of flammable gas be maintained below 20 percent of the lower explosive limit. This provision is intended to prevent fires and explosions that could result from explosive concentrations of flammable gases. The OPS regulation at 49 CFR §192.751 addresses the same safety problem, requiring pipeline operators to "minimize the danger at accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion.” This OPS regulation therefore preempts enforcement of Subsection 1926.651(g)(1)(iii) against employers who are subject to the DOT standard. **Interpretation: PI-ZZ-039 Date: 07-19-1990**

	(Preemption of Certain OSHA Excavation Standards) Section 4(b)(1) of the Occupational Safety and Health Act (OSH Act) provides that OSHA does not apply to working conditions with respect to which other Federal agencies "exercise statutory authority to prescribe or enforce standards or regulations affecting occupational safety or health." §192.751 addresses the same safety problem, requiring pipeline operators to "minimize the danger at accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion." This OPS regulation therefore preempts enforcement of Subsection §1926.651(g)(1)(iii) against employers who are subject to the DOT standard. **Interpretation: PI-85-002 Date: 03-20-1985** In 49 CFR Part 192, our goal is to set standards for what must be accomplished leaving the operator discretion to develop specific methods of complying that fit conditions on the pipeline and permitting the use of appropriate new, or improved technology. There are a number of guidelines which provide specific ways to remove “each potential source of ignition” as required by §192.751, including the ones cited in your letter. **Interpretation: PI-ZZ-034 Date: 01-10-1984** Knowing that the natural gas distribution system's odorant will be absorbed by the passage of natural gas through soil if a leak occurs underground, what duty does an operator have under sec. 192.751 to post warning signs to minimize the danger of accidental ignition of gas in occupied structures alongside of which an underground service line runs? For example, does the operator have a duty to warn the occupant-customer that digging near the service line might cause a leak that won't be detectable by smell? There are no specific requirements relevant to the circumstances you describe.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	GPTC Guide Material is available.

Guidance Information	1. Applicable procedures should be reviewed during an inspection.
	2. The operator must have procedures.
	3. Typically, these procedures prohibit, restrict, and/or control the following activities where the presence of gas might constitute a fire or explosion hazard:
	   a. smoking/open flames
	   b. operating internal combustion engines
	   c. activities that could generate static electricity or electrical arcing

	d. welding, cutting, and other hot work e. using non-intrinsically safe equipment, unless monitoring for the presence of a hazardous atmosphere f. working on compressor engine or appurtenances g. working inside pipeline compressor and regulator buildings h. the use of spark-producing hand tools; etc. i. the means and locations for venting of gas. E.g., the presence of overhead power lines (CPF 1-2008-1007M) j. purging and blow down operations 4. Operator's performance of procedures should be observed, if feasible. 5. Review the operator's hot work permit, if available. 6. Applicable records should be reviewed to assure steps were taken to prevent accidental ignition such as: a. hot work/equipment permits b. proper grounding c. monitoring for presence of a hazardous atmosphere d. gas source isolation (positive shut-off) purge e. lock-out/tag-out f. warning signs, where appropriate g. written purge or blow down plans 7. A fire extinguisher must be provided when a hazardous amount of gas is being vented. 8. Maintenance and construction activities conducted where gas may be present should prohibit the use of tools, materials, fabrics, slings, etc. that may produce static discharge. 9. Operator should take precautions to minimize the potential of accumulating gas. 10. Spark-arresting techniques should be applied under certain hazardous conditions. 11. Consideration of all sources of ignition should be included in safety plans. 12. Operators should maintain restricted access to hazardous areas, including safety zones for vehicular and air space domains. 13. The operator should consider environmental factors such as weather conditions and terrain when venting gas.
Examples of a Probable Violation	1. The lack of procedures is a violation of §192.605. 2. The lack of records is a violation of §192.603. 3. The operator did not follow written procedures. 4. Appropriate warning signs are not posted. 5. When venting gas, fire extinguishers were not present. 6. Potential sources of ignition are not removed, or gas is not properly vented outside of a facility. 7. Evidence that ignition took place. 8. Use of improper tools and equipment. 9. Failure to monitor for the presence of a hazardous atmosphere.
Examples of Evidence	1. Operator's written procedures. 2. Observed or documented violation of ignition prevention procedures. 3. Photographs. 4. Incident reports. 5. Hot work permits.

	6. Documented statements by operator personnel. 7. The lack of procedures or records.
Other Special Notations	