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*Sections of the Code of Federal Regulations to which additions have been made.

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Subpart A—General

192.1 Scope of part.

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to:

(1) Offshore gathering of gas upstream from the outlet flange of each facility on the outer continental shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; and

(2) Onshore gathering of gas outside of the following areas:

(i) An area within the limits of any incorporated or unincorporated city, town, or village.

(ii) Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.

192.3 Definitions.

As used in this part—

"Distribution Line" means a pipeline other than a gathering or transmission line.

"Gas" means natural gas, flammable gas, or gas which is toxic or corrosive.

"Gathering Line" means a pipeline that transports gas from a current production facility to a transmission line or main.

"High pressure distribution system" means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

"Listed specification" means a specification listed in section I of Appendix B of this part.

"Low-pressure distribution system" means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

"Main" means a distribution line that serves as a common source of supply for more than one service line.

"Maximum actual operating pressure" means the maximum pressure that occurs during normal operations over a period of 1 year.

"Maximum allowable operating pressure" means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

"Municipality" means a city, county, or any other political subdivision of a state.

"Offshore" means 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.

"Operator" means a person who engages in the transportation of gas.

"Person" means 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.

"Pipe" means any pipe or tubing used in the transportation of gas, including pipe-type holders.

"Pipeline" means 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.

"Pipeline facility" means new and existing pipelines, 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.

"Secretary" means the secretary of transportation or any person to whom he has delegated authority in the matter concerned.

"Service line" means a distribution line that transports gas from a common source of supply to (1) a customer meter or the connection to a customer's piping, whichever is farther downstream, or (2) the connection to a customer's piping if there is no customer meter. A customer meter is the meter that measures the transfer of gas from an operator to a consumer.

"SMYS" means specified minimum yield strength is—

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with 192.107 (b).

"State" means each of the several states, the District of Columbia, and the Commonwealth of Puerto Rico.

"Transmission line" means a pipeline, other than a gathering line, that—

(1) Transports gas from a gathering line or storage facility to a distribution center or storage facility;

(2) Operates at a hoop stress of 20 percent or more of SMYS; or

(3) Transports gas within a storage field.

"Transportation of gas" means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

192.5 Class locations.

(a) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d) (2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit is counted as a separate building intended for human occupancy.

(b) A Class 1 location is any class location unit that has 10 or less buildings intended for human occupancy.

(c) A Class 2 location is any class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is—

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of any of the following:

(i) A building that is occupied by 20 or more persons during normal use.

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly.

(e) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(f) The boundaries of the class locations determined in accordance with paragraphs (a) through (e) of this section may be adjusted as follows:

(1) A Class 4 location ends 220 yards from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 3 location, the Class 3 location ends 220 yards from the nearest building in the cluster.

(3) When a cluster of buildings intended for human occupancy requires a Class 2 location, the Class 2 location ends 220 yards from the nearest building in the cluster.

192.7 Incorporation by reference.

(a) Any documents or parts thereof incorporated by reference in this part are a part of this regulation as though set out in full.

(b) All incorporated documents are available for inspection in the Office of Pipeline Safety, Room 107, 400 Sixth Street SW., Washington, D.C. In addition, the documents are available at the addresses provided in Appendix A to this part.

(c) The full titles for the publications incorporated by reference in this part are provided in Appendix A to this part.

192.9 Gathering lines.

Each gathering line must comply with the requirements of this part applicable to transmission lines.

192.11 Petroleum gas systems.

(a) No operator may transport petroleum gas in a system that serves 10 or more customers, or in a system, any portion of which is located in a public place (such as a highway), unless that system meets the requirements of this part and of NFPA Standards No. 58 and No. 59. In the event of a conflict, the requirements of this part prevail.

(b) Each petroleum gas system covered by paragraph (a) of this section must comply with the following:

(1) Aboveground structures must have open vents near the floor level.

(2) Belowground structures must have forced ventilation that will prevent any accumulation of gas.

(3) Relief valve discharge vents must be located so as to prevent any accumulation of gas at or below ground level.

(4) Special precautions must be taken to provide adequate ventilation where excavations are made to repair an underground system.

(c) For the purpose of this section, petroleum gas means propane, butane, or mixtures of these gases, other than a gas air mixture that is used to supplement supplies in a natural gas distribution system.

192.12 Liquefied natural gas facilities.

(a) Except for a pipeline facility in operation or under construction before January 1, 1973, no operator may store, treat or transfer liquefied natural gas in a pipeline facility unless that pipeline facility meets the applicable requirements of this part and of NFPA Standard No. 59A.

(b) No operator may store, treat, or transfer liquefied natural gas in a pipeline facility in operation or under construction before January 1, 1973, unless—

(1) The facility is operated in accordance with the applicable operating requirements of this part and of NFPA Standard 59A; and

(2) Each modification or repair made to the facility after December 31, 1972, conforms to the applicable requirements of this part and NFPA Standard 59A, insofar as is practicable.

192.13 General

(a) No person may operate a segment of pipeline that is readied for service after March 12, 1971, or in the case of an offshore gathering line, after July 31, 1977, unless that pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part.

(b) No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed after November 12, 1970, or in the case of an offshore gathering line, after July 31, 1977, unless that replacement, relocation, or change has been made in accordance with this part.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

192.15 Rules of regulatory construction.

(a) As used in this part—

"Includes" means including but not limited to.

"May" means "is permitted to" or "is authorized to".

"May not" means "is not permitted to" or "is not authorized to".

"Shall" is used in the mandatory and imperative sense.

(b) In this part—

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

192.17 Filing of inspection and maintenance plans.

(a) Except as provided in paragraph (b) of this section, each operator shall file with the secretary not later than February 1, 1971, a plan for inspection and maintenance of each pipeline facility which he owns or operates. In addition, each change to an inspection and maintenance plan must be filed with the secretary within 20 days after the change is made.

(b) The provisions of paragraph (a) of this section do not apply to pipeline facilities—

(1) That are subject to the jurisdiction of a state agency that has submitted a certification or agreement with respect to those facilities under section 5 of the Natural Gas Pipeline Safety Act (49 U.S.C. 1675); and

(2) For which an inspection and maintenance plan is required to be filed with that state agency.

(c) Plans filed with the secretary must be sent to the office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590.

Subpart B—Materials

192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

192.53 General.

Materials for pipe and components must be—

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated.

PSC 192.53 (a) Some of the materials conforming to specifications approved for use under this code may not have properties suitable for the lower portion of the temperature band covered by this code. Engineers are cautioned to give attention to the low-temperature properties of the materials used for facilities to be exposed to unusually low ground temperatures or low atmospheric temperatures. Twenty (20) inch steel pipe and larger, with a specified minimum yield strength of 52,000 p.s.i. or higher, shall be tested for fracture toughness in accordance with the applicable section of respective API standard under which it was produced, except for small lot purchases of pipe where testing for fracture toughness is impractical.

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

PSC 192.53 (d) When substantial quantities of pipe are acquired certified reports of chemical composition and physical properties shall be obtained; when the quantity of pipe involved is so limited that this requirement would be impractical, a certified statement shall be obtained setting forth the specification under which the pipe was manufactured.

192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if—

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of Appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of Appendix B to this part; or

(3) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(4) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch.

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, 49 USC 1672; 40 FR 43901, 49 CFR 1.53).

PSC 192.313 *(a) (5) Smooth bends on pipe 4 inches in size and smaller shall have a difference between the maximum and minimum diameter of not more than 12.5 percent of the nominal diameter.*

(b) Each circumferential weld of steel pipe that is subjected to stress during bending must be nondestructively tested.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch.

(d) Each bend, other than a wrinkle bend made in accordance with 192.315, must have a smooth contour and be free of mechanical damage.

192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30%, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches or larger in diameter, the bend may not have a deflection of more than 1½° for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

192.317 Protection from hazards.

(a) Each transmission line or main must be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, offshore pipelines must be protected from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20% or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

PSC 192.319 *(a) This includes grading the ditch so that the pipe has a firm, substantially continuous bearing on the bottom of the ditch. When long sections of pipe that have been welded alongside the ditch are lowered in, care shall be exercised so as not to jerk the pipe or impose any strains that may kink or put a permanent bend in the pipe.*

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that—

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

PSC 192.319 *(b) (3) If there are large rocks in the material to be used for backfill, care should be used to prevent damage to the coating or pipe by such means as the use of rock shield material, or by making the initial fill with rock free material to a sufficient depth over the pipe to prevent rock damage.*

PSC 192.319 *(b) (4) Where flooding of the trench is done to consolidate the backfill, care shall be exercised to see that the pipe is not floated from its firm bearing on the trench bottom.*

PSC 192.319 *(c) The provisions of 192.319 (a) shall also apply to mains operating at less than 20% of the SMYS.*

192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches, except that pipe with an outside diameter of 0.875 inches or less may have a minimum wall thickness of 0.062 inches.

(e) Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

PSC 192.321 *(f) The casing pipe shall be reamed and cleaned to the extent necessary to remove any sharp edges, projections, or abrasive material which could damage the plastic during and after insertion. That portion of the plastic piping which spans disturbed earth shall be adequately protected by a bridging piece or other means from crushing or shearing from external loading or settling of backfill. Care shall be taken to prevent the plastic piping from bearing on the end of the casing.*

PSC 192.321 *(g) Care shall be exercised to avoid rough handling of plastic pipe and tubing. It shall not be pushed or pulled over sharp projections, dropped or have other objects dropped upon it. Caution shall be taken to prevent kinking or buckling, and any kinks or buckles which occur shall be removed by cutting out as a cylinder.*

PSC 192.321 *(h) Changes in direction of plastic piping may be made with bends, tees or elbows under the following limitations:*

(1) Plastic pipe and tubing may be deflected to a radius not less than the minimum recommended by the manufacturer for the kind, type, grade, wall thickness and diameter of the particular plastic used.

(2) The bends shall be free of buckles, cracks, or other evidence of damage.

(3) Changes in direction that cannot be made in accordance with PSC 192.321 (h) (1) above shall be made with elbow-type fittings.

(4) Miter bends are not permitted.

(5) Branch connections shall be made only with socket-type tees or other suitable fittings specifically designed for the purpose.

PSC 192.321 *(i) Plastic piping shall be laid on undisturbed or well compacted soil. If plastic piping is to be laid in soils which may damage it, the piping shall be protected by suitable rock free materials before back-filling is completed. Plastic piping shall not be supported by blocking. Well tampered earth or other continuous support shall be used.*

192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72% of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

PSC 192.323 *(e) Casing requirements of highway authorities shall be followed; however, construction type shall not be any less than provided by this code.*

192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

PSC192.325 *(b) If the structure is a public building where people assemble or in areas such as playground, assembly ground, or park, wherever possible the clearance shall be at least 100 feet if the main is operated at more than 100 p.s.i. but less than 500 p.s.i. and shall be at least 150 feet if operated at 500 p.s.i. or more. If these clearances cannot be maintained, then the next higher type of construction shall be used except such construction may be pressure-tested the same as the remainder of the line. No distribution main or transmission line shall be installed under buildings.*

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in 192.175 (b).

192.327 Cover.

(a) Except as provided in paragraphs (c) and (e) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal Soil	Consolidated rock
	Inches	Inches
Class 1 location	30	18
Class 2, 3, and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches of cover if the law of the State or municipality—

(1) Establishes a minimum cover of less than 24 inches;

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock, and all pipe installed in any offshore location under water less than 12 feet deep, as measured from mean low tide, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom. However, less than the minimum cover is permitted in accordance with paragraph (c) of this section.

Subpart H—Customer Meters, Service Regulators, and Service Lines

192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

192.353 Customer meters and regulators: location.

(a) Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage. However, the upstream regulator in a series may be buried.

Subpart I—Requirements for Corrosion Control

192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) Notwithstanding the deadlines for compliance in this subpart, the corrosion control requirements of this subpart do not apply to offshore gathering lines until August 1, 1977.

192.453 General.

Each operator shall establish procedures to implement the requirements of this subpart. These procedures, including those for the design, installation, operation and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.

192.455 External corrosion control: buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b) and (c) of this section, each buried or submerged pipeline installed after July 31, 1971 must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of 192.46.

(2) It must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this subpart, installed and placed in operation within one year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion, accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode, or an electrode using close spacing, not to exceed 20 feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a) (2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a) (2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

192.457 External corrosion control: buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must, not later than August 1, 1974, be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must, not later than August 1, 1976, be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines. The operator shall determine the areas of of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

(c) For the purpose of this subpart, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

PSC 192.457 (d) Notwithstanding the provisions of 192.457 (b) (regarding active corrosion), effectively coated steel distribution pipelines, except for those portions including services and short sections that because of their nature and installation make cathodic protection impractical and uneconomical, must, not later than August 1, 1975, be cathodically protected along the entire area that is effectively coated in accordance with this subpart.

192.459 External corrosion control: examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion is found, remedial action must be taken to the extent required by 192.483 and the applicable paragraphs of 192.485, 192.487, or 192.489.

192.461 External corrosion control: protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfiling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

192.463 External corrosion control: cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this subpart. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

192.465 External corrosion control: monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exeeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected service lines or short sections of protected mains, not in excess of 100 feet, these service lines and mains may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) At intervals not exceeding 2 months, each cathodic protection rectifier or other impressed current power source must be inspected to ensure that it is operating.

(c) At intervals not exeeding 2 months, each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection, must be electrically checked for proper performance. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by paragraphs (b) and (c) of 192.455 and paragraph (b) of 192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

192.467 External corrosion control: electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) An insulating device must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

192.469 External corrosion control: test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurements to determine the adequacy of cathodic protection.

192.471 External corrosion control: test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

192.473 External corrosion control: interference currents.

(a) After July 31, 1973, each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

192.475 Internal corrosion control: general.

(a) After July 31, 1972, corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of 192.485, 192.487 or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.1 grain of hydrogen sulfide per 100 standard cubic feet may not be stored in pipe-type or bottle-type holders.

192.477 Internal corrosion control: monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. After July 31, 1972, each coupon or other means of monitoring internal corrosion must be checked at intervals not exceeding 6 months.

192.479 Atmospheric corrosion control: general.

(a) *Pipelines installed after July 31, 1971.* Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.

(b) *Pipelines installed before August 1, 1971.* Not later than August 1, 1974, each operator having an aboveground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall—

(1) Determine the areas of atmospheric corrosion on the pipeline;

(2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of 192.485, 192.487, or 192.489; and

(3) Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.

§ 192.481 Atmospheric corrosion control: monitoring.

After meeting the requirements of § § 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and 1 year for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

192.483 Remedial measures: general.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

192.485 Remedial measures: transmission lines.

(a) *General corrosion.* Each segment of transmission line pipe with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, must be replaced or the operating pressure reduced commensurate with the actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

192.487 Remedial measures: distribution lines other than cast iron or ductile iron lines.

(a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of the paragraph.

(b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

(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.

(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.

(d) Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

192.617 Investigation of failures. 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.

192.619 Maximum allowable operating pressure: steel or plastic pipelines.

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds 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.

(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.

PSC 192.619 *(a) (2) (i) For plastic pipe used as a gas service, the maximum allowable operating pressure in any class location shall not exceed 60 p.s.i.g.*

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

	Factors*	
Class location	Segment installed before (Nov. 12, 1970)	Segment installed after (Nov. 11, 1970)
1	1.1	1.1
2	1.25	1.25
3	1.4	1.5
4	1.4	1.5

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

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, (or in the case of offshore gathering lines, July 1, 1976) unless the segment was tested in accordance with paragraph (a) (2) of this section after July 1, 1965, (or in the case of offshore gathering lines, July 1, 1976) or the segment was uprated in accordance with Subpart K of this part.

(4) For furnace butt welded steel pipe, a pressure equal to 60% of the mill test pressure to which the pipe was subjected.

(5) For steel pipe other than furnace butt welded pipe, a pressure equal to 85% of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

(6) 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) (6) 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) Notwithstanding the other requirements of this section, 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 July 1, 1970, or in the case of offshore gathering lines, July 1, 1976, subject to the requirements of 192.611.

192.621 Maximum allowable operating pressure: high-pressure distribution systems.

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

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

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

(3) Twenty-five p.s.i.g. in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

PSC 192.621 *(a) (3) No person may operate a segment of a cast iron pipe in which there are unreinforced bell and spigot joints at a pressure higher than low pressure unless it can be proven to the commission that they can be operated at a higher pressure. However, the maximum allowable operating pressure under any circumstances shall not exceed 15 p.s.i.g.*

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

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

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

PSC 192.621 *(c) Sixty p.s.i.g. in individual distribution systems or portions thereof. The intercity or supply mains for these distribution systems may be operated at higher pressures provided by this code if the number of services supplied from these mains are limited and these mains are not an integral part of the distribution system. The pressure and the services supplied from these higher pressure intercity and supply mains shall be limited to 60 p.s.i.g. unless the service lines are equipped with series regulators or other pressure limiting devices as prescribed in 192.197 (c)*

192.623 Maximum and minimum allowable operating pressure: low-pressure distribution systems.

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

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

PSC 192.623 *(c) No person may operate a low pressure distribution system at a pressure in excess of that provided by section PSC 134.23 (1).*

192.625 Odorization of gas.

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

(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 of which it is intended;

(B) Reduces the activity of a catalyst; or

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

(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.

(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) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section.

(g) The odorization requirements of Part 190 of this chapter, as in effect on August 12, 1970, must be complied with, in each State in which odorization of gas in transmission lines is required by that part, until the earlier of the following dates:

(1) January 1, 1977; or

(2) The date upon which the distribution companies in that State are odorizing gas in accordance with paragraphs (a) through (f) of this section.

192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

192.629 Purging of pipelines.

(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.

PSC 192.629 (c) No pipeline, main, or service shall be purged into any building or confined space.

Subpart M—Maintenance

192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

192.703 General.

(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.

192.705 Transmission lines: patrolling.

(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:

Class location of line	Maximum intervals between patrols	
	At highway and railroad crossings	At all other places
1, 2	6 months	1 year
3	3 months	6 months
4	do	3 months

192.706 Transmission lines; leakage surveys.

(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 1 year. However, in the case of a transmission line which transports gas in conformity with section 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(1) In Class 3 locations, at intervals not exceeding 6 months; and

(2) In Class 4 locations, at intervals not exceeding 3 months.

192.707 Line markers for mains and transmission lines.

(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, railroad, and navigable waterway; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

However, until January 1, 1978, paragraphs (a) (l) and (a) (2) of this section do not apply to mains installed before April 21, 1975, and until January 1, 1978, paragraph (a) (l) of this section does not apply to transmission lines installed before April 21, 1975.

(b) *Exceptions for buried pipelines.* Line markers are not required for buried mains and transmission lines—

(1) Located offshore or under inland navigable waters;

(2) In Class 3 or Class 4 locations—

(i) Where placement of a marker is impractical; or

(ii) Where a program for preventing interference with underground pipelines is established by law; or

(3) In the case of navigable waterway crossings, within 100 feet of a line marker placed and maintained at that waterway in accordance with this section.

(c) *Pipelines aboveground.* Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Markers other than at navigable waterways.* The following must be written legibly on a background of sharply contrasting color on each line marker not placed at a navigable waterway.

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with one-quarter inch stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

(e) *Markers at navigable waterways.* Each line marker at a navigable waterway must have the following characteristics:

(1) A sign, rectangular in shape, with a narrow strip along each edge colored international orange and the area between lettering on the sign and boundary strips colored white.

(2) Written on the sign in block style, black letters—

(i) The word "Warning," "Caution," or "Danger" followed by the words "Do Not Anchor or Dredge" and the words "Gas Pipeline Crossing"; and

(ii) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

(3) In overcast daylight, the sign is visible and the writing required by paragraph (e) (2) (i) of this section is legible, from approaching or passing vessels that may damage or interfere with the pipeline.

(f) *Existing markers.* Line markers installed before April 21, 1975, which do not comply with paragraph (d) or (e) of this section may be used until January 1, 1980.

PSC 192.707

When transmission lines are located outside urban areas, their location shall be marked (recognizable to the public) at each fence line, road crossing, railroad crossing, river, lake, stream, or drainage ditch crossing and wherever it is considered necessary to identify the location of a pipeline to reduce the possibility of damage or interference.

192.709 Transmission lines: record-keeping.

Each operator shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service.

192.711 Transmission lines: general requirements for repair procedures.

(a) 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% of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery. As soon as feasible, the operator shall make permanent repairs.

(b) Except as provided in 192.717 (c), no operator may use a welded patch as a means of repair.

192.713 Transmission lines: permanent field repair of imperfections and damages.

(a) Except as provided in paragraph (b) of this section each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40% of SMYS must be repaired as follows:

(1) If it is feasible, to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage.

(3) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.

PSC 192.713 (d) Gouges and grooves of lesser depth than 10% of the nominal wall thickness of the pipe may be removed by grinding out to a smooth contour provided the grinding does not reduce the remaining wall thickness to less than the minimum prescribed by this code for the conditions of use.

192.715 Transmission lines: permanent field repair of welds. Each weld that is unacceptable under 192.241 (c) must be repaired as follows:

(a) If is 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% of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least ⅛-inch 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.

PSC 192.717 Transmission lines: permanent field repair of leaks.

(a) Except as provided in paragraph (b) of this section, each permanent field repair of a leak on a transmission line must be made as follows:

(1) If feasible, the segment of transmission line must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design, unless the transmission line—

(i) Is joined by mechanical couplings; and

(ii) Operates at less than 40 percent of SMYS.

(3) If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; or, if the leak is due to a corrosion pit and on pipe of not more than 40,000 psi SMYS, the repair may be made by fillet welding 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.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

192.719 Transmission lines: testing of repairs.

(a) *Testing of replacement pipe.* (1) 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.

(2) The test required by subparagraph (1) of this paragraph may be made on the pipe before it is installed, but all field girth bolt welds that are not strength tested must be tested after installation by nondestructive tests meeting the requirements of 192.243.

(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.

PSC 192.720 *Repair of steel pipe operating below 40% of the specified minimum yield strength.*

If inspections at any time reveal an injurious defect, gouge, groove, dent, or leak, immediate temporary measures shall be employed to protect the property and public if it is not feasible to make permanent repair at time of discovery. As soon as feasible, permanent repairs shall be made using recognized methods of repair.

192.721 Distribution systems: patrolling.

(a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patroled at intervals not exceeding 3 months.

PSC 192.722 Distribution mains: markers.

When distribution mains are located outside urban areas, their location shall be marked (recognizable to the public) at each fence line, road crossing, railroad crossing, river, lake, stream, or drainage ditch crossing and wherever it is considered necessary to identify the location of a pipeline to reduce the possibility of damage or interference.

192.723 Distribution systems: leakage surveys and procedures.

(a) Each operator of a distribution system shall provide for periodic leakage surveys in its operating and maintenance plan.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A gas detector survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 1 year.

(2) Leakage surveys of the distribution system outside of the principal business areas must be made as frequently as necessary, but at intervals not exceeding 5 years.

PSC 192.723

Every operator shall maintain a gas leak-detection program and shall maintain records of operation under the program. The program shall consist of not less than the following:

(a) In principal business districts (as shown by maps filed with the public service commission by each utility) a reasonable street-opening survey shall be conducted twice annually by making tests with combustible gas indicators in street openings such as telephone and electric vaults and manholes, catch basins and sewer system manholes, and gas system openings.

(b) In each principal business district a building survey shall be conducted once a year. The piping from the service entrance to the meter outlet and metering and regulating equipment shall be tested for gas leakage in those buildings that have gas service.

(c) A survey of all buildings used for public gatherings such as schools, churches, hospitals, and theaters shall be conducted once each year. The piping from the service entrance to the meter outlet and metering and regulating equipment shall be tested for gas leakage.

(d) In residential areas, in addition to a survey of public buildings the vegetation shall be checked. At least 3 barhole tests shall be made in each block; at least one street opening shall be checked if one exists in each block or at each intersection; and on streets where system is operating at a pressure of more than 10 p.s.i.g., all street openings shall be checked. (See 192.723 (b) (1) above for types of street openings.) The utility may substitute for the barhole tests a ground surface survey with a hand-operated, continuous-sampling instrument capable of detecting combustible gas in air concentrations of 100 parts per million. The utility may substitute for all the tests required by this section (PSC 192.723 (d)) a survey by mobile flame ionization or infrared gas detection units, provided that a method be included to check individual services. The tests required by this section (PSC 192.723 (d)) shall be made each year.

(e) Along lines in rural areas, the vegetation shall be checked annually.

(f) When a leak complaint is received and the odor of gas indicates that there is a leak in or near the premises, a search shall be carried to conclusion until such leak is found.

PSC 192.724 Further leakage survey after repair of leak.

When a leak is found and repaired, a further check shall be made in the vicinity of the repaired leak to determine if there is any other source of migrant gas in the neighborhood.

192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

192.727 Abandonment or inactivation of facilities.

(a) Each operator shall provide in its operating and maintenance plan for abandonment or deactivation of pipelines, including provisions for meeting each of 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 off-shore 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.

PSC 192.727 *(d) Special efforts shall be made to include services which have not been used for two years in a way that will remove gas from the customers' premises. The plan shall include the following provisions:*

(1) If the facilities are abandoned in place, they shall be physically disconnected from the piping system. The open ends of all abandoned facilities shall be capped, plugged, or otherwise effectively sealed.

(2) In cases where a main is abandoned, together with the service lines connected to it, insofar as service lines are concerned, only the customers' end of such service lines need be sealed as stipulated above.

192.729 Compressor stations: procedures for gas compressor units.

Each operator shall establish starting, operating, and shutdown procedures for gas compressor units.

192.731 Compressor stations: inspection and testing of relief devices.

(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 to exceed 1 year, to determine that it functions properly.

192.733 Compressor stations: isolation of equipment for maintenance or alterations.

Each operator shall establish procedures for maintaining compressor stations, including provisions for isolating units or sections of pipe for purging before returning to service.

192.735 Compressor stations: storage of combustible materials.

(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) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

PSC 192.735 *(c) All aboveground oil or gasoline storage tanks shall be constructed and protected in accordance with the applicable codes of the department of industry, labor and human relations.*

192.737 Pipe-type and bottle-type holders: plan for inspection and testing.

Each operator having a pipe-type or bottle-type holder shall establish a plan for the systematic, routine inspection and testing of these facilities, including the following:

(a) Provision must be made for detecting external corrosion before the strength of the container has been impaired.

(b) Periodic sampling and testing of gas in storage must be made to determine the dew point of vapors contained in the stored gas, that if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant.

(c) The pressure control and pressure limiting equipment must be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity.

192.739 Pressure limiting and regulating stations: inspection and testing.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected, at intervals not exceeding 1 year, to inspections and tests to determine that it is—

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

192.741 Pressure limiting and regulating stations: telemetering or recording gages.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gages to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gages in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high- or low-pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

PSC 192.741 *(d) Each low pressure distribution system must be equipped with telemetering or recording pressure gage or gages as may be required to properly indicate the gas pressure in the system at all times. At least once each year the pressure variation shall be determined throughout each system.*

192.743 Pressure limiting and regulating stations: testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 1 year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made, at intervals not exceeding one year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

PSC 192.744 Service regulators and associated safety devices: inspection and testing.

Company service regulators and associated safety devices on customers' premises shall be inspected and tested periodically to determine whether they are in proper operating condition. The above shall include testing of the set pressure of the regulator at a specific flow rate, determination of the lock-up pressure, and determine as to whether there are any leaks, internal or external, associated with the regulator. The test interval shall be the same as the interval between meter changes in the meter rotation program. (See section PSC 134.30.)

192.745 Valve maintenance: transmission lines.

Each transmission line valve that might be required during any emergency must be inspected and partially operated, at intervals not exceeding 1 year.

192.747 Valve maintenance: distribution systems.

Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced, at intervals not exceeding 1 year.

PSC 192.747

(a) Inspection shall include checking of alignment to permit use of a key or wrench and clearing from the valve box or vault any

debris which would interfere or delay the operation of the valve. Records shall be maintained to show specific valve location and such records shall be made continuously accessible to authorized personnel for use under emergency conditions.

(b) Existing connections in the form of inline valves between low pressure gas distribution systems and high pressure gas distribution systems shall be physically severed by January 1, 1974.

(c) The by-pass valves in district regulator stations supplying gas to a low pressure distribution system shall be sealed, locked or otherwise be rendered incapable of operation, except by authorized personnel by January 1, 1974.

192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet or more, must be inspected, at intervals not exceeding 1 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.

192.751 Prevention of accidental ignition.

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.

PSC 192.751 *(d) Whenever the accidental ignition in the open air of gas-air mixture might be likely to cause personal injury or property damage, precautions shall be taken as, for example:*

(1) Prohibit smoking and open flames in the area, and

(2) Install a metallic bond around the location of cuts in gas pipes to be made by other means than cutting torches, and

(3) Take precautions to prevent static electricity sparks, and

(4) Provide fire extinguishers of appropriate size and type in accordance with the department of industry, labor and human relations' requirements.

PSC 192.753 Caulked bell and spigot joints.

(a) Each cast-iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i.g. or more must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which—

(i) Does not reduce the flexibility of the joint;

(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of 192.53 (a) and (b) and 192.143.

PSC 192.753

Existing unreinforced bell and spigot jointed cast iron pipe shall be operated at low pressure unless it can be proved to the commission that they can be satisfactorily operated at a higher pressure. However, the operating pressure under any circumstances shall not exceed 15 p.s.i.g.

PSC 192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth-movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of 192.317 (a), 192.319, and 192.361 (b) - (d).

APPENDIX A—INCORPORATED BY REFERENCE

I. List of organizations and addresses.

A. American National Standards Institute (ANSI), 1430 Broadway, New York, N. Y. 10018 (formerly the United States of American Standards Institute (USASI)). All current standards issued by USASI and ASA have been redesigned as American National Standards and continued in effect.

B. American Petroleum Institute (API), 1801 K Street NW, Washington, D.C. 20006, or 300 Corrigan Tower Building, Dallas, Texas, 75201.

C. The American Society of Mechanical Engineers (ASME) United Engineering Center, 345 East 47th Street, New York, N. Y. 10017.

D. American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.

E. Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 1815 North Fort Myer Drive, Room 913, Arlington, Va. 22209.

F. National Fire Protection Association (NFPA), 470 Atlantic Avenue, Boston, Mass. 02110.

II. Documents incorporated by reference. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to pipe or components which were manufactured, designed, or installed before July 1, 1976, unless otherwise provided in this part.

A. American Petroleum Institute:

(1) API Standard 5A "API Specifications for Casing, Tubing, and Drill Pipe" (1968, 1971, 1973 plus Supp. 1).

(2) API Standard 6A "API Specification for Wellhead Equipment" (1968, 1974).

(3) API Standard 6D "API Specification for Pipeline Valves" (1968, 1974).

(4) API Standard 5L "API Specification for Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(5) API Standard 5LS "API Specification for Spiral-Weld Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(6) API Standard 5LX "API Specification for High-Test Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(7) API Recommended Practice 5LI "API Recommended Practice for Railroad Transportation of Line Pipe" (1967, 1972).

(8) API Standard 1104 "Standard for Welding Pipe Lines and Related Facilities" (1968, 1973).

B. The American Society for Testing and Materials:

(1) ASTM Specification A53 "Standard Specification for Welded and Seamless Steel Pipe" (A53-65, A53-68, A53-73).

(2) ASTM Specification A72 "Standard Specification for Welded Wrought-Iron Pipe" (A72-64T, A72-68).

(3) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-66, A106-68, A106-72a).

(4) ASTM Specification A134 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Sizes 16 in. and over" (A134-64, A134-68, A134-73).

(5) ASTM Specification A135 "Standard Specification for Electric-Resistance-Welded Steel Pipe" (A135-63T, A135-68, A135-73a).

(6) ASTM Specification A139 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (Sizes 4 in. and over)" (A139-64, A139-68, A139-73).

(7) ASTM Specification A155 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service" (A155-65, A155-68, A155-72a).

(8) ASTM Specification A211 "Standard Specification for Spiral-Welded Steel or Iron Pipe" (A211-63, A211-68, A211-73).

(9) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (A333-64, A333-67, A333-73).

(10) ASTM Specification A372 "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessel" (A372-67, A372-71).

(11) ASTM Specification A377 "Standard Specifications for Cast Iron and Ductile Iron Pressure Pipe" (A377-66, A377-73).

(12) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for High-Pressure Transmission Systems" (A381-66, A381-68, A381-73).

(13) ASTM Specification A539 "Standard Specification for Electric Resistance-Welded Coiled Steel Tubing for Gas and Fuel Oil Lines" (A539-65, A539-73).

(14) ASTM Specification B42 "Standard Specification for Seamless Copper Pipe, Standard Sizes" (B42-62, B42-66, B42-72).

(15) ASTM Specification B68 "Standard Specification for Seamless Copper Tube, Bright Annealed" (B68-65, B68-68, B68-74).

(16) ASTM Specification B75 "Standard Specification for Seamless Copper Tube" (B75-65, B75-68, B75-74).

(17) ASTM Specification B88 "Standard Specification for Seamless Copper Water Tube" (B88-66, B88-72).

(18) ASTM Specification B251 "Standard Specification for General Requirements for Wrought Seamless Copper and Copper-Alloy Tube" (B251-66, B251-68, B251-72).

(19) ASTM Specification D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-66T, D2513-68, D2513-70, D2513-71, D2513-73, D2513-74a).

(20) ASTM Specification D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-66T, D2517-67, D2517-73).

C. The American National Standards Institute, Inc.:

(1) ANSI A21.1 "Thickness Design of Cast-Iron Pipe" (A21.1-1967, A21.1-1972).

(2) ANSI A21.3 "Specifications for Cast Iron Pit Cast Pipe for Gas" (A21.3-1953).

(3) ANSI A21.7 "Cast-Iron Pipe Centrifugally Cast in Metal Molds for Gas" (A21.7-1962).

(4) ANSI A21.9 "Cast-Iron Pipe Centrifugally Cast in Sand-Lined Molds for Gas" (A21.9-1962).

(5) ANSI A21.11 "Rubber-Gasket Joints for Cast-Iron and Ductile-Iron Pressure Pipe and Fittings" (A21.11-1964, A21.11-1972).

(6) ANSI A21.50 "Thickness Design of Ductile-Iron Pipe" (A21.50-1965, A21.50-1971).

(7) ANSI A21.52 "Ductile-Iron Pipe, Centrifugally Cast, in Metal Molds or Sand-Lined Molds for Gas" (A21.52-1965, A21.52-1971).

(8) ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (B16.1-1967).

(9) ANSI B16.5 "Steel Pipe Flanges, Flanged Valves and Fittings (B16.5-1968, B16.5-1973).

(10) ANSI B16.24 "Bronze Flanges and Flanged Fittings" (B16.24-1962, B16.10-1971).

(11) ANSI B36.10 "Wrought Steel and Wrought Iron Pipe" (B36.10-1959, B36.10-1970).

(12) ANSI C1 "National Electrical Code" (C1-1968, C1-1975).

D. The American Society of Mechanical Engineers:

(1) ASME Boiler and Pressure Vessel Code Section VIII "Pressure Vessels, Division 1" (1968, 1974).

(2) ASME Boiler and Pressure Vessel Code, Section IX "Welding Qualifications" (1968, 1974).

E. Manufacturer's Standardization Society of the Valve and Fittings Industry:

(1) MSP-25 "Standard Marking System for Valves, Fittings, Flanges, and Union" (1964).

(2) MSS SP-44 "Steel Pipe Line Flanges" (1955, 1972, 1975).

(3) MSS SP-52 "Cast Iron Pipe Line Valves" (1957).

(4) MSS SP-70 "Cast Iron Gate Valves, Flanged and Threaded Ends" (1970).

(5) MSS Sp-71 "Cast Iron Swing Check Valves, Flanged and Threaded Ends" (1970).

(6) MSS Sp-78 "Cast Iron Plug Valves" (1972).

F. National Fire Protection Association:

(1) NFPA Standard 30 "Flammable and Combustible Liquids Code" (1969, 1973).

(2) NFPA Standard 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1969, 1972).

(3) NFPA Standard 59 "Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1968).

(4) NFPA Standard 59A "Storage and Handling Liquefied Natural Gas" (1971, 1972).

Appendix B—Qualification of Pipe

I. Listed Pipe Specifications. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to pipe or components which were manufactured, designed, or installed before July 1, 1976, unless otherwise provided in this Part.

API 5L—Steel and iron pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

API 5LS—Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

API 5LX—Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

ASTM A53—Steel pipe (1965, 1968, 1973).

ASTM A72—Wrought Iron Pipe (1964T, 1968).

ASTM A106—Steel pipe (1966, 1968, 1972a).

ASTM A134—Steel pipe (1964, 1968, 1973).

ASTM A135—Steel pipe (1963T, 1968, 1973a).

ASTM A139—Steel pipe (1964, 1968, 1973).

ASTM A155—Steel pipe (1965, 1968, 1972a).

ASTM A211—Steel and iron pipe (1963, 1968, 1973).

ASTM A333—Steel pipe (1964, 1967, 1973).

ASTM A377—Cast iron pipe (1966, 1973).

ASTM A381—Steel pipe (1966, 1968, 1973).

ASTM A539—Steel tubing (1965, 1973).

ASTM B42—Copper pipe (1962, 1966, 1972).

ASTM B68—Copper tubing (1965, 1968, 1974).

ASTM B75—Copper tubing (1965, 1968, 1974).

ASTM B88—Copper tubing (1966, 1972).

ASTM B251—Copper pipe and tubing (1966, 1968, 1972).

ASTM D2513—Thermoplastic pipe and tubing (1966T, 1968, 1970, 1971, 1973, 1974a).

ASTM D2517—Thermosetting plastic pipe and tubing (1966T, 1967, 1973).

ANSI A21.3—Cast iron pipe (1953).

ANSI A21.7—Cast iron pipe (1962).

ANSI A21.9—Cast iron pipe (1962).

ANSI A21.52—Ductile iron pipe (1965, 1971).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches in diameter, the pipe must meet the requirements of the flattening test set forth in ASTM A53, except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under Subpart E of this part. The weld must be made under the most severe conditions which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104. If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code. The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i.g. or less, or the tensile properties may be established by performing tensile tests as set forth in API Standard 5LX. All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests—All Sizes

10 lengths or less—1 set of tests for each length.

11 to 100 lengths—1 set of tests for each 5 lengths, but not less than 10 tests.

Over 100 lengths—1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in 192.55 (c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with Subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this part, the test pressure must be maintained for at least 8 hours.

APPENDIX C—QUALIFICATION FOR WELDERS OF LOW STRESS LEVEL PIPE

I. *Basic test.* The test is made on pipe 12 inches or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than ⅛-inch long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. *Additional tests for welders of service line connections to mains.* A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fittings and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work each about 8 inches long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

APPENDIX D—CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

I. *Criteria for cathodic protection—A. Steel, cast iron, and ductile iron structures.*

(1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. *Aluminum structures.* (1) Except as provided in subparagraph (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift

of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in subparagraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary, may suffer corrosion resulting from the buildup of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of the cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by subparagraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraph A (1) and (2) and paragraph B (1) of section I of this appendix.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A (3), B (2), and C of section I of this appendix.

IV. *Reference half cells.* A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to —0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KC1 calomel half cell: —0.78 volt.

(2) Silver-silver chloride half cell used in sea water:—0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

History: Cr. Register, May, 1972, No. 197, eff. 6-1-72; cr. 192.12, 192.379, appendix A-II F 4; am. 192.201 (a), 192.625 (g) (1), 192.717 (b), 192.727, Register, February, 1973, No. 206, eff. 3-1-73; am. PSC 192.457 (d), PSC 192.613 (c) (1), Register, June, 1974, No. 222, eff. 7-1-74; am. 192.3, 192.55 (a) (2) and (b) (2), 192.65, 192.197 (a), 192.625 (g) (1), appendix A-I, B, and II A, 1., 2., 3., and 5., appendix B, I, cr. appendix B, III, Register, December, 1974, No. 228, eff. 1-1-75; am. 192.59 (a) (1), (b) (1) and cr. (c), am. 192.65 (a), 192.225 (a), 192.227 (a) (2), 192.229 (c), 192.241 (c), 192.625 (a) and (b), 192.625 (g) (1), 192.705 (a) and (b), r. 192.705 (c), cr. 192.706, am. 192.707, appendix A II and appendix B I, Register, March, 1976, No. 243, eff. 4-1-76.