PSC 134, 135

CERTIFICATE

STATE OF WISCONSIN) ss. 2-U-3829
PUBLIC SERVICE COMMISSION) 80-237

TO ALL WHOM THESE PRESENTS SHALL COME, GREETINGS:

I, Jacqueline K. Reynolds, Secretary of the Public Service Commission of Wisconsin, and custodian of the official records of said commission, do hereby certify that the annexed order amending Wis. Adm. Code chapters PSC 134 and 135 concerning rules and regulations governing the construction, operation and maintenance of facilities for the production, transmission, distribution and utilization of gas was duly approved and adopted by this commission on August 25, 1981.

I further certify that said copy has been compared by me with the original on file in this commission and that the same is a true copy thereof, and of the whole of such original.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed the official seal of the commission at the Hill Farms State Office Building, in the City of Madison this 31st day of August, 1981.

Jacqueline K. Reynolds

Jacqueline K. Reynolds
Secretary to the Commission
PUBLIC SERVICE COMMISSION OF WISCONSIN

12-1-81

DATE MAILED
AUG 26 1981

BEFORE THE

PUBLIC SERVICE COMMISSION OF WISCONSIN

Rules and Regulations Governing the Construction, Operation and Maintenance of Facilities for the Production, Transmission, Distribution and Utilization of Gas	))))	2-U-3829

ORDER OF THE PUBLIC SERVICE COMMISSION ADOPTING, REPEALING AND AMENDING RULES

Relating to rules governing the construction, operation and maintenance of facilities for the production, transmission, distribution and utilization of gas.

Analysis Prepared by the Public Service Commission.

On November 7, 1980 the Public Service Commission issued a notice of hearing on proposed amendments and additions to Chapter PSC 135, Wis. Adm. Code. That chapter now contains Part 192, 49 Code of Federal Regulations: Minimum Safety Standards for Pipeline Facilities and Transportation of Gas established by the Federal Department of Transportation, Office of Pipeline Safety Operations.

Under 49 USC ss. 1674(a) and (c) a state may certify to the Department of Transportation that it has adopted federal pipeline safety rules as its own and is enforcing these federal standards. In exchange for this certification, the Secretary of the Department of Transportation is required to provide 50% of the cost of a state's safety program.

The Public Service Commission of Wisconsin participates in the Department of Transportation certification program and enforces the federal standards as its own. When amendments to the federal standards are adopted by the Office of Pipeline Safety Operations, the Public Service Commission must adopt those amendments as its own to meet the certification requirements of 49 USC 1674(a).

Recent amendments to the federal gas pipeline safety rules require that the PSC adopt these rules as its own to continue its certification under 49 USC ss. 1674(a). The amendments contained in the attached appendices accomplish the following changes:

1. Appendix A contains two minor amendments to correct printing errors in ss. PSC 134.02(b)(c) and 135.09, and Part 192 CFR, as contained in Chapter PSC 135, Wis. Adm. Code.

2. Appendix B contains various amendments to PSC 192, as contained in Chapter PSC 135.

3. Appendix C contains sections of a new PSC 193, Liquefied Natural Gas Facilities: Federal Safety Standards, to follow PSC 192 in Chapter PSC 135.

RULES AND STATUTORY AUTHORITY

Pursuant to authority vested in the Public Service Commission by ss. 196.745 and 227.021, Wis. Stats., the Public Service Commission amends and adopts rules as specified in Appendices A, B and C.

The rules contained in the attached appendices shall take effect on the first day of the month following their publication in the Wisconsin Administrative Register, as provided in s. 227.026(1), Wis. Stats.

Dated at Madison, Wisconsin, August 25, 1981

By the Commission.

Jacqueline K. Reynolds

Jacqueline K. Reynolds, Secretary to the Commission

<u>Appendix A</u>

CORRECTIONS

1. Section PSC 134.02(6)(e) is amended to read as follows (p. 232, Wis. Adm. Code):

   (e) Total calorific value. Total calorific value of a gas is the number of British thermal units evolved by the complete combustion, at constant pressure, of one standard cubic foot of gas with air, the temperature of the gas, air, and products of combustion being 60° F. and all water formed by the combustion reaction condensed to the liquid state.

2. Section PSC 135.09(1) is amended to read as follows (p. 255, Wis. Adm. Code):

   PSC 135.09 ADOPTION OF FEDERAL MINIMUM SAFETY STANDARDS. (1) The federal department of transportation, office of pipeline safety, pursuant to the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1675--et seq.) has established minimum safety standards for pipeline facilities and the transportation of gas, as set forth in part 192 <u>and part 193</u> in title 49, Code of Federal Regulations. In accordance with the Natural Gas Pipeline Safety Act of 1968 and requirments of the federal department of transportation, such minimum safety standards are hereby adopted as state safety standards. (The numbering system and sequence used in said minimum safety standards are herein used for convenience and clarity.) Additions have been made to the minimum safety standards of the federal department of transportation as adopted herein and follow the section of the adopted federal standards to which the additions directly relate or if the additions do not directly relate to any particular adopted federal standard the additions are inserted in the numbering sequence within the appropriate subpart. In all cases the additions appear in italics preceded by PSC 192 plus the appropriate section number. Copies of the publications referred to are available for inspection at the office of the public service commission, the secretary of state and the revisor of statutes or may be procured for personal use from the addresses listed in Appendix A - Incorporated by Reference, I. Lists of organizations and addresses, which follows section PSC 192.753.

Appendix A

(cont'd)

3. Section PSC 192.749 (as contained in Chapter PSC 135, Wis. Adm. Code index) is amended to read as follows (p. 258, Wis. Adm. Code):

192.749 ~~Valve~~ Vault maintenance.

4. Section PSC 192.12 (as contained in Chapter PSC 135, Wis. Adm. Code) is repealed (pages 261, 262, Wis. Adm. Code).

5. Section PSC 192.107(b)(1) (as contained in Chapter PSC 135, Wis. Adm. Code) is amended to read (p. 267, Wis. Adm. Code):

(1) If the pipe is tensile tested in accordance with section 11 D of Appendix B to this part, the lower of the following:

6. Section PSC 192.121(a) (as contained in Chapter PSC 135, Wis. Adm. Code) is amended to read as follows (p. 270, Wis. Adm. Code):

192.121 DESIGN OF PLASTIC PIPE.

~~(a)~~ The design pressure for plastic pipe is determined in accordance with the following formula, subject to the limitations of s. 192.123:

$$P = 2S \frac{t}{(D-t)} \times 0.32$$

P = Design pressure, gage, ~~R~~kPa (psi).
S = For thermoplastic pipe the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 23° C. (73° F.), 38° C. (100° F.), 49° C. (120° F.), or 60° C. (140° F.); for reinforced thermosetting plastic pipe, 75,800 kPa (11,000 psi).
t = Specified wall thickness, mm (in.).
D = Specified outside diameter, mm (in.).

~~(b)--The-design-factor-for-plastic-pipe-is-determined as-follows:~~

Appendix A

(cont'd)

~~Class location~~	~~Design factor~~
~~1~~	~~0.32~~
~~2~~	~~0.25~~
~~3~~	~~0.25~~
~~4~~	~~0.20~~

7. Section PSC 192.175(b) (as contained in Chapter PSC 135, Wis. Adm. Code) is amended to read as follows (p. 276-2, Wis. Adm. Code):

192.175 PIPE-TYPE AND BOTTLE-TYPE HOLDERS.

(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

$$C = \frac{3DxPxF}{1,000}$$

in which:

C = Minimum clearance between pipe containers or bottles in inches.
D = Outside diameter of pipe containers or bottles in inches.
P = Maximum allowable operating pressure, p.s.i.g.
F = Design factor as set forth in 192.111 of this part.

8. Section PSC 192.375 (as contained in Chapter PSC 135, Wis. Adm. Code) is amended to read as follows (p. 276-2, Wis. Adm. Code):

PSC 192.375(a)(3) *The above ground portion of the plastic service line is completely enclosed in a rigid metal tube or metal pipe. The metal tube or pipe shall have a minimum wall thickness of 0.035 in., adequate protection against corrosion, and shall extend a minimum of 6 inches below grade.*

(b) Each plastic service line inside a building must be protected against external damage.

Appendix A
(cont'd)

9. Section PSC 192.727(d) (as contained in Chapter PSC 135, Wis. Adm. Code) is amended to read (p. 328, Wis. Adm. Code):

   192.727 ~~(d)~~(g) *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.

10. Sections IIA(5) and (6) of Appendix A to Chapter PSC 192 (as contained in Chapter PSC 135, Wis. Adm. Code) is amended to read as follows (p. 333, Wis. Adm. Code):

   (5) API Standards 5LS "API Specification for Spiral-Weld Line Pipe" (1967, 1980, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

   (6) API Standard 5LX "API Specification for High-Test Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

11. Section I of Appendix B to Chapter PSC 192 (as contained in Chapter PSC 135, Wis. Adm. Code) is amended to read:

   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 the latest edition is adopted unless otherwise provided in this part.

Appendix A
(cont'd)

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 plus Supp. 1 and 1977).

API 5LX - Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1 and 1977).

Appendix B

Part 192 of Title 49, Code of Federal Regulations, as contained in Chapter PSC 135, Wis. Adm. Code, is amended as follows:

1. Section 192.281(a) is amended to read (p. 291, Wis. Adm. Code):

192.281 Plastic pipe.

(a) *General.* ~~Each-plastic-pipe-joint-must-be made-in-accordance-with-written-procedures-that-have been-proven-by-destructive-burst-test-to-produce-joints at-least-as-strong-as-the-pipe-being-joined.~~ A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

Section 192.283 is created to read:

192.283 Plastic pipe; qualifying joining procedures.

(a) *Heat Fusion, Solvent Cement and Adhesive Joints.* Before any written procedure established under ss. 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of --

(i) In the case of thermoplastic pipe, paragraph 8.6 (Sustained Pressure Test) or paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513; or

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Pressure Test) of ASTM D2517.

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

Appendix B
(cont'd)

(3) For procedures intended for nonlateral pipe connections, follow the tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical Joints.* Before any written procedure established under ss. 192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D638-77a (except for conditioning).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 5.0 mm (0.20 in.) per minute, plus or minus 2.5 percent.

(4) Pipe specimens less than 102 mm (4 in.) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 102 mm (4 in.) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 55.6° C. (100° F.) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results, or the manufacturer's rating, whichever is lower, must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

Appendix B

(cont'd)

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980 may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

3. Section 192.285 is created to read:

(b) The specimen joint must be --

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under ss. 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is --

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint areas; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person--

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under ss. 192.513.

Appendix B
(cont'd)

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

4. Section 192.287 is created to read:

192.287 Plastic pipe; inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by ss. 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

5. In Section II.B. of Appendix A (page 334) items (19) and (20) are amended as follows, and a new item (19) is created to read:

~~(19)~~ (20) 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)~~ (21) ASTM Specification D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-66T, D2517-67, D2517-73).

(19) ASTM Specification D638 "Standard Test Method for Tensile Properties of Plastic" (D638-77a).

6. Subpart F of the Table of Contents to Part 192 (page 256) is amended by creating new sections 192.283, 192.285 and 192.287 as follows:

192.283 Plastic pipe; qualifying joining procedures.
192.285 Plastic pipe; qualifying persons to make joints.
192.287 Plastic pipe; inspection of joints.

Appendix B

(cont'd)

7. Section 192.713(4) is renumbered section 192.713(a)(4) (page 324) and placed following 192.713(a)(3).

PSC 192.713 (a)(4) *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.*

8. Section 192.465(a) is amended to read as follows:

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 exceeding 15 months, to determine whether the cathodic protection meets the requirements of section 192.463. However, if tests at those intervals are impractical for separately protected ~~service lines~~ or short sections of protected mains or transmission lines, not in excess of 100 feet, ~~these-service-lines~~ or separately protected service lines, these pipelines ~~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.

9. Section 192.711(b) is amended by deleting the reference to "ss. 192.717(c)" and inserting in lieu thereof ss. 192.717(a)(3)."

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

Appendix B

(cont'd)

(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~~(e)~~(a)(3), no operator may use a welded patch as a means of repair.

Appendix C

PART 193, TITLE 49, CODE OF FEDERAL REGULATIONS

The Introduction to Part 193 should read as follows:

WISCONSIN CODE ADOPTION
OF
PART 193 IN TITLE 49
CODE OF FEDERAL REGULATIONS

Title 49. Code of Federal Regulations is amended by adding a new Part 193 to read as follows:

PART 193--LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

Subpart A--General

Sec.

Subpart B--Siting Requirements

Subpart C--Design

LNG Storage Tanks

Design of Transfer Systems

Subpart D--Construction

Authority: 49 U.S.C. 1671 et seq.; 49 CFR 1.53, Appendix A of Part 1, and Appendix A of Part 106.

Subpart A—General

§ 193.2001 Scope of part.

(a) This part prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that is subject to the Natural Gas Pipeline Safety Act of 1968 and Part 192 of this chapter.

(b) This part does not apply to—

(1) LNG facilities used by ultimate consumers of LNG or natural gas.

(2) LNG facilities used in the course of natural gas treatment or hydrocarbon extraction which do not store LNG.

(3) In the case of a marine cargo transfer system and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.

(4) Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).

§ 193.2003 Semisolid facilities.

An LNG facility used in the transportation or storage of LNG in a semisolid state need not comply with any requirement of this part which the Director finds impractical or unnecessary because of the semisolid state of LNG. In making such a finding, the Director may impose appropriate alternative safety conditions.

§ 193.2005 Applicability.

(a) New or amended standards in this part governing the siting, design, installation, or construction of an LNG facility and related personnel qualifications and training do not apply to—

(1) LNG facilities under construction before the date such standards are published; or

(2) LNG facilities for which an application for approval of the siting, construction, or operation was filed before March 1, 1978, with the Department of Energy (or any predecessor organization of that Department) or the appropriate State or local agency in the case of any facility not subject to the jurisdiction of the Department of Energy under the Natural Gas Act (not including any facility the construction of which began after November 29, 1979, not pursuant to such an approval).

(b) If an LNG facility listed in paragraph (a) of this section is replaced, relocated, or significantly altered after February 11, 1980, the replacement, relocated facility, or significantly altered facility must comply with the applicable requirements of this part governing siting, design, installation, and construction, except that—

(1) The siting requirements apply only to LNG storage tanks that are significantly altered by increasing the original storage capacity or relocated, not pursuant to an application for approval filed as provided by paragraph (a)(2) of this section before March 1, 1978; and

(2) To the extent compliance with the design, installation, and construction requirements would make the replaced, relocated, or altered facility incompatible with other facilities or would otherwise be impracticable, the replaced, relocated, or significantly altered facility may be designed, installed, or constructed in accordance with the original specifications for the facility, or in a manner that the Director finds acceptable.

(c) The siting, design, installation, and construction of an LNG facility under construction before February 11, 1980, or that is listed in paragraph (a)(2) of this section (except a facility under construction before July 1, 1976) must meet the applicable requirements of NFPA 59A (1972 edition) and Part 192 of this chapter or the applicable requirements of this part, except that no Part 192 standard issued after March 1, 1978, applies to an LNG facility listed in paragraph (a)(2) of this section.

§ 193.2007 Definitions.

As used in this part—

"Ambient vaporizer" means a vaporizer which derives heat from naturally occurring heat sources, such as the atmosphere, sea water, surface waters, or geothermal waters.

"Cargo transfer system" means a component, or system of components functioning as a unit, used exclusively for transferring hazardous fluids in bulk between a tank car, tank truck, or marine vessel and a storage tank.

"Component" means any part, or system of parts functioning as a unit, including, but not limited to, piping, processing equipment, containers, control devices, impounding systems, lighting, security devices, fire control equipment, and communication equipment, whose integrity or reliability is necessary to maintain safety in controlling, processing, or containing a hazardous fluid.

"Container" means a component other than piping that contains a hazardous fluid.

"Control system" means a component, or system of components functioning as a unit, including control valves and sensing, warning, relief, shutdown, and other control devices, which is activated either manually or automatically to establish or maintain the performance of another component.

"Controllable emergency" means an emergency where reasonable and prudent action can prevent harm to people or property.

"Design pressure" means the pressure used in the design of components for the purpose of determining the minimum permissible thickness or physical characteristics of its various parts. When applicable, static head shall be included in the design pressure to determine the thickness of any specific part.

"Determine" means make an appropriate investigation using scientific methods, reach a decision based on sound engineering judgment, and be able to demonstrate the basis of the decision.

"Dike" means the perimeter of an impounding space forming a barrier to prevent liquid from flowing in an unintended direction.

"Director" means Director of the Materials Transportation Bureau or any person to whom authority in the matter concerned has been delegated.

"Emergency" means a deviation from normal operation, a structural failure, or severe environmental conditions that probably would cause harm to people or property.

"Exclusion zone" means an area surrounding an LNG facility in which an operator or government agency legally controls all activities in accordance with § 193.2057 and § 193.2059 for as long as the facility is in operation.

"Fail-safe" means a design feature which will maintain or result in a safe condition in the event of malfunction or failure of a power supply, component, or control device.

"g" means the standard acceleration of gravity of 9.806 metre per second^2 (32.17 feet per second^2).

"Gas," except when designated as inert, means natural gas, other flammable gas, or gas which is toxic or corrosive.

"Hazardous fluid" means gas or hazardous liquid.

"Hazardous liquid" means LNG or a liquid that is flammable or toxic.

"Heated vaporizer" means a vaporizer which derives heat from other than naturally occurring heat sources.

"Impounding space" means a volume of space formed by dikes and floors which is designed to confine a spill of hazardous liquid.

"Impounding system" includes an impounding space, including dikes and floors for conducting the flow of spilled hazardous liquids to an impounding space.

"Liquefied natural gas" or "LNG" means natural gas or synthetic gas having methane (CH_4) as its major constituent which has been changed to a liquid or semisolid.

"LNG facility" means a pipeline facility that is used for liquefying or solidifying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas.

"LNG plant" means an LNG facility or system of LNG facilities functioning as a unit.

"m^3" means a volumetric unit which is one cubic metre, 6.2898 barrels, 35.3147 ft.^{3}, or 264.1720 U.S. gallons, each volume being considered as equal to the other.

"Maximum allowable working pressure" means the maximum gage pressure permissible at the top of the equipment, containers or pressure vessels while operating at design temperature.

"Normal operation" means functioning within ranges of pressure, temperature, flow, or other operating criteria required by this part.

"Operator" means a person who owns or operates an LNG facility.

"Person" means any individual, firm, joint venture, partnership, corportation, association, state, municipality, cooperative association, or joint stock association and includes any trustee, receiver, assignee, or personal representative thereof.

"Pipeline facility" means new and existing piping, 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.

"Piping" means pipe, tubing, hoses, fittings, valves, pumps, connections, safety devices or related components for containing the flow of hazardous fluids.

"Storage tank" means a container for storing a hazardous fluid, including an underground cavern.

"Transfer piping" means a system of permanent and temporary piping used for transferring hazardous fluids between any of the following: liquefaction process facilities, storage tanks, vaporizers, compressors, cargo transfer systems, and facilities other than pipeline facilities.

"Transer system" includes transfer piping and cargo transfer system.

"Waterfront LNG plant" means an LNG plant with docks, wharves, piers, or other structures in, on, or immediately adjacent to the navigable waters of the United States or Puerto Rico and any shore area immediately adjacent to those waters to which vessels may be secured and at which LNG cargo operations may be conducted.

"Vaporization" means an addition of thermal energy changing a liquid or semisolid to a vapor or gaseous state.

"Vaporizer" means a heat transfer facility designed to introduce thermal energy in a controlled manner for changing a liquid or semisolid to a vapor or gaseous state.

§ 193.2009 Rules of regulatory construction.

(a) As used in this part—

(1) "Includes" means including but not limited to;

(2) "May" means is permitted to or is authorized to;

(3) "May not" means is not permitted to or is not authorized to; and

(4) "Shall" or "must" is used in the mandatory and imperative sense.

(b) In this part—

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

(2) Words importing the plural include the singular.

§ 193.2011 Reporting.

Leaks and spills of LNG must be reported in accordance with the requirements of Part 191 of this chapter.

§ 193.2013 Incorporation by reference.

(a) There are incorporated by reference in this Part all materials referred to in this Part that are not set forth in full. The incorporated materials are deemed published under 5 U.S.C. 552(a) and 1 CFR Part 51 and are part of this regulation as though set forth in full. All incorporated materials are listed in Appendix A to this Part 193 with the applicable editions in parentheses following the title of the referenced material. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to components which are designed, manufactured, or installed in accordance with the earlier edition before the latest edition is adopted, unless otherwise provided in this part. The incorporated materials are subject to change, but any change will be announced by publication in the Federal Register before it becomes effective.

(b) All incorporated materials are available for inspection in the Materials Transportation Bureau, U.S. Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590, and at the Office of the Federal Register Library, 1100 L Street, NW., Washington, D.C. In addition, copies of the incorporated materials are available from the respective organizations listed in Appendix A to this Part 193.

(c) Incorporated by reference provisions approved by the Director of the Federal Register.

(49 U.S.C. 1674 (a); 49 CFR 1.53 and Appendix A to Part 1)

§ 193.2015 Petitions for finding or approval.

Where a rule in this part authorizes the Director to make a finding or approval, any operator may petition the Director to make such finding or approval. Petitions must be sent to the Director, Materials Transportation Bureau, 400 7th Street, SW., Washington, D.C. 20590, and be received at least 90 days before the operator requests that the finding or approval be made. Each petition must refer to the rule authorizing the action sought and contain information or arguments that justify the action. Unless otherwise specified, no public proceeding is held on a petition before it is granted or denied. Within 90 days after a petition is received, the Director notifies the petitioner of the disposition of the petition or, if the request requires more extensive consideration or additional information or comments are requested and delay is expected, of the date by which action will be taken.

§ 193.2017 Plans and procedures.

(a) Each operator shall maintain at each LNG plant the plans and procedures required for that plant by this part. The plans and procedures must be available upon request for review and inspection by the Director or any State Agency that has submitted a current certification or agreement with respect to the plant under section 5 of the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1674). In addition, each change to the plans or procedures must be available at the LNG plant for review and inspection within 20 days after the change is made.

(b) The Director or the State Agency, after notice and opportunity for hearing, may require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

Subpart B—Siting Requirements

§ 193.2051 Scope.

This subpart prescribes siting requirements for the following LNG facilities: Containers and their impounding systems, transfer systems and their impounding systems, emergency shutdown control systems, fire control systems, and associated foundations, support systems, and normal or auxiliary power facilities necessary to maintain safety.

§ 193.2055 General.

An LNG facility must be located at a site of suitable size, topography, and configuration so that the facility can be designed to minimize the hazards to persons and offsite property resulting from leaks and spills of LNG and other hazardous fluids at the site. In selecting a site, each operator shall determine all site-related characteristics which could jeopardize the integrity and security of the facility. A site must provide ease of access so that personnel, equipment, and materials from offsite locations can reach the site for fire fighting or controlling spill associated hazards or for evacuation of personnel.

§ 193.2057 Thermal radiation protection.

(a) *Thermal exclusion zone.* Each LNG container and LNG transfer system must have a thermal exclusion zone in accordance with the following:

(1) Within the thermal exclusion zone, the impounding system may not be located closer to targets listed in paragraph (d) of this section than the exclusion distance "d" determined according to this section, unless the target is a pipeline facility of the operator.

(2) If grading and drainage are used under § 193.2149(b), operators must comply with the requirements of this section by assuming the space needed for drainage and collection of spilled liquid is an impounding system.

(b) *Measurement.* The exclusion distance "d" is measured along the line (PT), as shown in the following impoundment diagram, where the following apply:

(1) T is a point on the target that is closest to (P).

(2) D is a point closest to (T) on the top inside edge of the innermost dike.

(3) θ is one of the following angles with the vertical, to account for flame tilt and potential preignition vapor formation:

(i) An assumed angle of $(\theta)=45°$; or

(ii) An angle determined in accordance with a mathematical model that meets the criteria of paragraph (c)(2) of this section, using the maximum wind speed that is exceeded less than 5 percent of the time based on recorded data for the area.

(4) L is one of the following lengths to account for flame height:

(i) An assumed length of $(L)=6(A/\pi)^{0.5}$, where (A) is the horizontal area across the impounding space measured at the lowest point along the top inside edge of the dike; or

(ii) A length determined in accordance with a mathematical model that meets the criteria of paragraph (c)(2) of this section, using appropriate parameters consistent with the time period that a target could be subjected to exposure before harm would result.

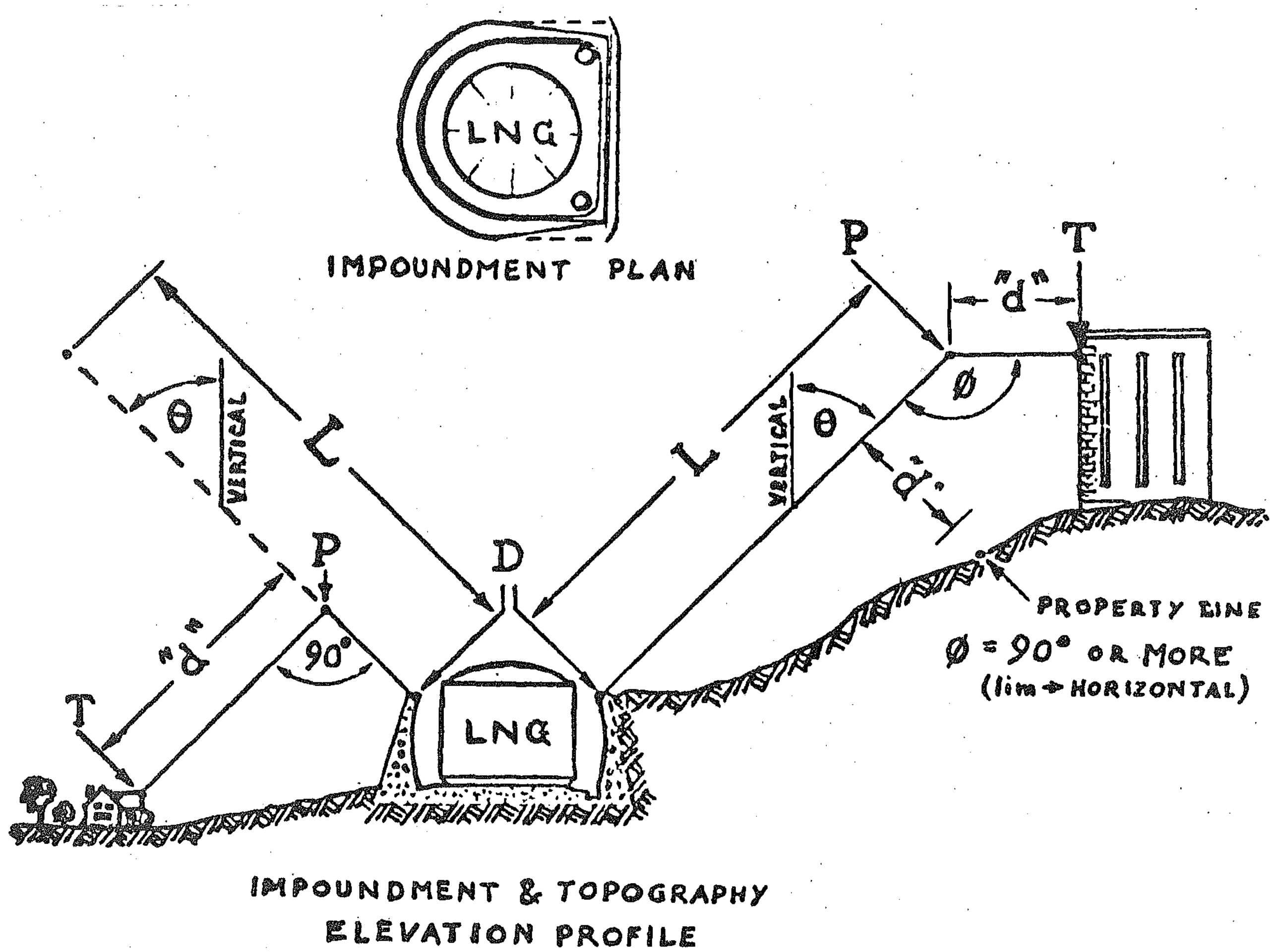
(5) PD is a line of length (L) or less, lying at angle θ in the vertical plane that intersects points (D) and (T).

(6) PT is a line lying in the vertical plane of line (PD), that:

(i) Is perpendicular to line (PD) when (PD) is less than (L); or

(ii) Has an angular elevation not above the horizontal at (P) when (PD) equals (L);

(7) P is the point where (PT) and (PD) intersect.



(c) *Exclusion distance length.* The length of an exclusion distance for each impounding space may not be less than the distance "d" determined in accordance with one of the following:

(1) $d = (f)(A)^{0.5}$, where

A = the largest horizontal area across the impounding space measured at the lowest point along the top inside edge of the dike.

f = values for targets prescribed in paragraph (d) of this section.

(2) Determine "d" from a mathematical model for thermal radiation and other appropriate fire characteristics which assures that the incident thermal flux levels in paragraph (d) of this section are not exceeded. The model must:

(i) Use atmospheric conditions which, if applicable, result in longer exclusion distances than other atmospheric conditions occurring at least 95 percent of the time based on recorded data for the site area;

(ii) Have been evaluated and verified by testing at a scale, considering scaling effects, appropriate for the range of application;

(iii) Have been submitted to the Director for approval, with supportive data as necessary to demonstrate validity; and

(iv) Have received approval by the Director.

(d) *Limiting values for incident radiant flux on offsite targets.* The maximum incident radiant flux at an offsite target from burning of a total spill in an impounding space must be limited to the distances in paragraph (c) of this section using the following values of "(f)" or "Incident Flux":

Offsite target	(f)	Incident flux Btu/ft.² hour
(1) Outdoor areas occupied by 20 or more persons during normal use, such as beaches, playgrounds, outdoor theaters, other recreation areas or other places of public assembly	(3)	1,600
(2) Buildings that are used for residences, or occupied by 20 or more persons during normal use	(1.6)	4,000
(3) Buildings made of cellulosic materials or are not fire resistant or do not provide durable shielding from thermal radiation that: (i) Have exceptional value, or contain objects of exceptional value based on historic uniqueness described in Federal, State, or local registers; (ii) Contain explosive, flammable, or toxic materials in hazardous quantities; or (iii) Could result in additional hazard if exposed to high levels of thermal radiation	(1.6)	4,000
(4) Structures that are fire resistant and provide durable shielding from thermal radiation that have the characteristics described in subdivisions (3)(i) through (3)(iii) above	(1.1)	6,700
(5) Public streets, highways, and mainlines of railroads—	(1.1)	6,700
(6) Other structures, or if closer to (P), the right-of-way of the property	(0.8)	10,000

§ 193.2059 Flammable vapor-gas dispersion protection.

(a) *Dispersion exclusion zone.* Except as provided by paragraph (e) of this section, each LNG container and LNG transfer system must have a dispersion exclusion zone with a boundary described by the minimum dispersion distance computed in accordance with this section. The following are prohibited in a dispersion exclusion zone unless it is an LNG facility of the operator:

(1) Outdoor areas occupied by 20 or more persons during normal use, such as beaches, playgrounds, outdoor theaters, other recreation areas, or other places of public assembly.

(2) Buildings that are:

(i) Used for residences;

(ii) Occupied by 20 or more persons during normal use;

(iii) Contain explosive, flammable, or toxic materials in hazardous quantities;

(iv) Have exceptional value or contain objects of exceptional value based on historic uniqueness described in Federal, State, or local registers; or

(v) Could result in additional hazard if exposed to a vapor-gas cloud.

(b) *Measuring dispersion distance.* The dispersion distance is measured radially from the inside edge of an impounding system along the ground contour to the exclusion zone boundary.

(c) *Computing dispersion distance.* A minimum dispersion distance must be computed for the impounding system. If grading and drainage are used under § 193.2149(b), operators must comply with the requirements of this section by assuming the space needed for drainage and collection of spilled liquid is an impounding system. Dispersion distance must be determined in accordance with the following dispersion parameters, using applicable parts of the mathematical model in Appendix B of the report, "Evaluation of LNG Vapor Control Methods," 1974, or a model for vapor dispersion which meets the requirements of subdivisions (ii) through (iv) in § 193.2057(c)(2):

(1) Average gas concentration in air = 2.5 percent.

(2) Dispersion conditions are a combination of those which result in longer predicted downwind dispersion distances than other weather conditions at the site at least 90 percent of the time, based on U.S. Government weather data, or as an alternative where the model used gives longer distances at lower wind speeds, Category F atmosphere, wind speed = 4.5 miles per hour, relative humidity equals 50.0 percent, and atmospheric temp 'ures = 0.0 C.

(3) L.spersion coordinates y, z, and H, where applicable, = 0.

(d) *'aporization design rate.* In computing dispersion distance under paragraph (c) of this section, the following applies:

(1) Vaporization results from the spill caused by an assumed rupture of a single transfer pipe (or multiple pipes that lack provisions to prevent parallel flow) which has the greatest overall flow capacity, discharging at maximum potential capacity, in accordance with the following conditions:

(i) The rate of vaporization is not less than the sum of flash vaporization and vaporization from boiling by heat transfer from contact surfaces during the time necessary for spill detection, instrument response, and automatic shutdown by the emergency shutdown system but, not less than 10 minutes, plus, in the case of impounding systems for LNG storage tanks with side or bottom penetrations, the time necessary for the liquid level in the tank to reach the level of the penetration or equilibrate with the liquid impounded assuming failure of the internal shutoff valve.

(ii) In determining variations in vaporization rate due to surface contact, the time necessary to wet 100 percent of the impounding floor area shall be determined by equation C-9 in the report "Evaluation of LNG Vapor Control Methods," 1974, or an alternate model which meets the requirements of subdivisions (ii) through (iv) in § 193.2057(c)(2).

(iii) After spill flow is terminated, the rate of vaporization is vaporization of the remaining spillage, if any, from boiling by heat transfer from contact surfaces that are reducing in area and temperature as a function of time.

(iv) Vapor detention space is all space provided for liquid impoundment and vapor detention outside the component served, less the volume occupied by the spilled liquid at the time the vapor escapes the vapor detention space.

(2) The boiling rate of LNG on which dispersion distance is based is determined using the weighted average value of the thermal properties of the contact surfaces in the impounding space determined from eight

representative experimental tests on the materials involved. If surfaces are insulated, the insulation must be designed, installed, and maintained so that it will retain its performance characteristics under spill conditions.

(e) *Planned vapor control.* An LNG facility need not have a dispersion exclusion zone if the Director finds that compliance with paragraph (a) of this section would be impractical and the operator prepares and follows a plan for controlling LNG vapor that is found acceptable by the Director. The plan must include circumstances under which LNG vapor is controlled to preclude the dispersion of a flammable mixture from the LNG facility under all predictable environmental conditions that could adversely affect control. The reliability of the method of control must be demonstrated by testing or experience with LNG spills.

§ 193.2061 Seismic investigation and design forces.

(a) Except for shop fabricated storage tanks of 70,000 gallons or less capacity mounted within 2 feet of the ground, if an LNG facility is located at a site in Zone 0 or 1 of the "Seismic Risk Map of the United States," UBC, each operator shall determine, based on a study of faults, hydrologic regime, and soil conditions, whether a potential exists at the site for surface faulting or soil liquefaction.

(b) Subject to paragraph (f) of this section, LNG facilities must be designed and built to withstand, without loss of structural or functional integrity, the following seismic design forces, as applicable:

(1) For LNG facilities (other than shop fabricated storage tanks of 70,000 gallons or less capacity mounted within 2 feet of the ground) located at a site in Puerto Rico in Zone 2, 3, or 4 of the "Seismic Risk Map of the United States," or at a site determined under paragraph (a) of this section to have a potential for surface faulting or soil liquefaction, the forces that could reasonably be expected to occur at the foundation of the facility due to the most critical ground motion, motion amplification, permanent differential ground displacement, soil liquefaction, and symmetric and assymmetric reaction forces resulting from hydrodynamic pressure and motion of contained liquid in interaction with the facility structure.

(2) For all other LNG facilities, the total lateral force set forth in UBC, Volume 1, corresponding to the zone of the "Seismic Risk Map of the United States" in which the facility is located, and a vertical force equal to the total lateral force.

(c) Each operator of an LNG facility to which paragraph (b)(1) of this section applies shall determine the seismic design forces on the basis of a detailed geotechnical investigation and in accordance with paragraphs (d) and (e) of this section. The investigation must include each of the following items that could reasonably be expected to affect the site and be sufficient in scope to identify all hazards that could reasonably be expected to affect the facility design:

(1) Identification and evaluation of faults, Quaternary activity of those faults, tectonic structures, static and dynamic properties of materials underlying the site, and, as applicable, tectonic provinces within 100 miles of the site;

(2) Identification and evaluation of all historically reported earthquakes which could affect the determination under this section of the most critical ground motion or differential displacement at the site when correlated with particular faults, tectonic structures, and tectonic provinces, as applicable; and

(3) Identification and evaluation of the hydrologic regime and the potential of liquefaction-induced soil failures.

(d) The most critical ground motion must be determined in accordance with paragraph (e) of this section either:

(1) Probabilistically, when the available earthquake data are sufficient to show that the yearly probability of exceedance of most critical ground motion is 10^{-4} or less; or

(2) Deterministically, when the available earthquake data are insufficient to provide probabilistic estimates, with the objective of determining a most critical ground motion with a yearly probability of exceedance of 10^{-4} or less.

(e) The determination of most critical ground motion, considering local and regional seismological conditions, must be made by using the following:

(1) A regionally appropriate attenuation relationship, assuming that earthquakes occur at a location on a fault, tectonic structure, or tectonic province, as applicable, which would cause the most critical seismic movement at the site, except that where epicenters of historically reported earthquakes cannot be reasonably related to known faults or tectonic structures, but are recognized as being within a specific tectonic province which is within 100 miles of the site, assume that those earthquakes occur within their respective provinces at a source closest to the site.

(2) A horizontal design response spectrum determined from the mean plus one standard deviation of a free-field horizontal elastic response spectra whose spectral amplitudes are consistent with values expected for the most critical ground motion.

(3) A vertical design response spectrum that is either two-thirds of the amplitude of the horizontal design response spectrum at all frequencies or equal to the horizontal design response spectrum where the site is located within 10 miles of the earthquake source.

(f) An LNG storage tank or its impounding system may not be located at a site where an investigation under paragraph (c) of this section shows that any of the following conditions exists unless the Director grants an approval for the site:

(1) The estimated design horizontal acceleration exceeds 0.2g at the tank or dike foundation.

(2) The specific local geologic and seismic data base is sufficient to predict future differential surface displacement beneath the tank and dike area, but displacement not exceeding 30 inches cannot be assured with a high level of confidence.

(3) The specific local geologic and seismic data base is not sufficient to predict future differential surface displacement beneath the tank and dike area, and the estimated cumulative displacement of a Quaternary fault within one mile of the tank foundation exceeds 60 inches.

(4) The potential for soil liquefaction cannot be accommodated by design and construction in accordance with paragraph (b)(1) of this section.

(g) An application for approval of a site under paragraph (f) of this section must provide at least the following:

(1) A detailed analysis and evaluation of the geologic and seismic characteristics of the site based on the geotechnical investigation performed under paragraph (c) of this section, with emphasis on prediction of near-field seismic response.

(2) The design plans and structural analysis for the tank, its impounding system, and related foundations, with a report demonstrating that the design requirements of this section are satisfied, including any test results or other documentation as appropriate.

(3) A description of safety-related features of the site or designs, in addition to those required by this part, if applicable, that would mitigate the potential effects of a catastrophic spill (e.g., remoteness or topographic features of the site, additional exclusion distances, or multiple barriers for containing or impounding LNG).

(h) Each container which does not have a structurally liquid-tight cover must have sufficient freeboard with an appropriate configuration to prevent the escape of liquid due to sloshing, wave action, and vertical liquid displacement caused by seismic action.

§ 193.2063 Flooding.

(a) Each operator shall determine the effects of flooding on an LNG facility site based on the worst occurrence in a 100-year period. The determination must take into account:

(1) Volume and velocity of the floodwater;

(2) Tsunamis (local, regional, and distant);

(3) Potential failure of dams;

(4) Predictable land developments which would affect runoff accumulation of water; and

(5) Tidal action.

(b) The effect of flooding determined under paragraph (a) of this section must be accommodated by location or design and construction, as applicable, to reasonably assure:

(1) The structural or functional integrity of LNG facilities; and

(2) Access from outside the LNG facility and movement of personnel and equipment about the LNG facility site for the control of fire and other emergencies.

§ 193.2065 Soil characteristics.

(a) Soil investigations including borings and other appropriate tests must be made at the site of each LNG facility to determine bearing capacity, settlement characteristics, potential for erosion, and other soil characteristics applicable to the integrity of the facility.

(b) The naturally occurring or designed soil characteristics at each LNG facility site must provide load bearing capacities, using appropriate safety factors, which can support the following loads without excessive lateral or vertical movement that causes a loss of the functional or structural integrity of the facility involved:

(1) Static loading caused by the facility and its contents and any hydrostatic testing of the facility; and

(2) Dynamic loading caused by movement of contents of the facility during normal operation, including flow, sloshing, and rollover.

§ 193.2067 Wind forces.

(a) LNG facilities must be designed to withstand without loss of structural or functional integrity:

(1) The direct effect of wind forces;

(2) The pressure differential between the interior and exterior of a confining, or partially confining, structure; and

(3) In the case of impounding systems for LNG storage tanks, impact forces and potential penetrations by wind borne missiles.

(b) The wind forces at the location of the specific facility must be based on one of the following:

(1) For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, applicable wind load data in ANSI A 58.1, 1972 edition.

(2) For all other LNG facilities—

(i) An assumed sustained wind velocity of not less than 200 miles per hour, unless the Director finds a lower velocity is justified by adequate supportive data; or

(ii) The most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

§ 193.2069 Other severe weather and natural conditions.

(a) In addition to the requirements of §§ 193.2061, 193.2063, 193.2065, and 193.2067, each operator shall determine from historical records and engineering studies the worst effect of other weather and natural conditions which may predictably occur at an LNG facility site.

(b) The facility must be located and designed so that such severe conditions cannot reasonably be expected to result in an emergency involving the factors listed in § 193.2063(b).

§ 193.2071 Adjacent activities.

(a) Each operator shall determine that present and reasonably foreseeable activities adjacent to an LNG facility site that could adversely affect the operation of the LNG facility or the safety of persons or offsite property, if damage to the facility occurs.

(b) An LNG facility must not be located where present or projected offsite activities would be reasonably expected to—

(1) Adversely affect the operation of any of its safety control systems;

(2) Cause failure of the facility; or

(3) Cause the facility not to meet the requirements of this part.

§ 193.2073 Separation of facilities.

Each LNG facility site must be large enough to provide for minimum separations between facilities and between facilities and the site boundary to—

(a) Permit movement of personnel, maintenance equipment, and emergency equipment around the facility; and

(b) Comply with distances specified in Sections 2–2.4 through 2–2.7 of NFPA 59A.

Subpart C—Design

§ 193.2101 Scope.

This subpart prescribes requirements for the selection and qualification of materials for components, and for the design and installation or construction of components and buildings, including separate requirements for impounding systems, LNG storage tanks, and transfer systems.

Materials

§ 193.2103 General.

Materials for all components must be—

(a) Able to maintain their structural integrity under all design loadings, including applicable environmental design forces under Subpart B of this part;

(b) Physically, chemically, and thermally compatible within design limits with any fluid or other materials with which they are in contact; and

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

§ 193.2105 Extreme temperatures; normal operations.

Each operator shall—

(a) Determine the range of temperatures to which components will be subjected during normal operations, including required testing, initial startup, cooldown operations, and shutdown conditions; and

(b) Use component materials that meet the design standards of this part for strength, ductility, and other properties throughout the entire range of temperatures to which the component will be subjected in normal operations.

§ 193.2107 Extreme temperatures, emergency conditions.

(a) Each operator shall determine the effects on components not normally exposed to extreme cold (including a component's foundation or support system) of contact by LNG or cold refrigerant that could result from error, a spill, or other emergency determined as required by this part.

(b) Each operator shall determine the effects on components (including their foundations or support systems) of the extreme heat which could result from an LNG or other hazardous fluid fire.

(c) Where the exposure determined under paragraph (a) or (b) of this section could result in a failure that would worsen the emergency, the component or its foundation or support system, as appropriate, must be:

(1) Made of material or constructed to be suitable for the extreme temperature to which it could be subjected; or

(2) Protected by insultation or other means that will delay failure due to extreme temperature in order to allow adequate time to take emergency responses.

(d) If a material that has low resistance to flame temperatures is used in any component containing a hazardous fluid, the material must be protected so that any heat resulting from a controllable emergency does not cause the release of fluid that would result in an uncontrollable emergency.

§ 193.2109 Insulation.

During normal operations, insulation materials must—

(a) Maintain insulating values;

(b) Withstand thermal and mechanical design loads; and

(c) Be covered with a material that is noncombustible in the installed state, is not subject to detrimental ultraviolet decay, and that can withstand the forces of wind according to ANSI A58.1 and anticipated loading which could occur in a controllable emergency.

§ 193.2111 Cold boxes.

All cold boxes must be made of noncombustible material and the insulation must be made of materials which are noncombustible in the installed condition.

§ 193.2113 Piping.

(a) Piping made of cast iron, malleable iron, or ductile iron may not be used to carry any cryogenic or hazardous fluids.

(b) Piping materials intended for normal use at temperatures below −28.9° C (−20° F) or for use under § 193.2107(c)(1) must be qualified by testing in accordance with ANSI B 31.3 to comply with § 193.2103(b).

§ 193.2115 Concrete subject to cryogenic temperatures.

Concrete intended for normal use at cryogenic temperatures or for use under § 193.2107(c)(1) may not be used unless—

(a) Materials, measurements, mixing, placing, prestressing, and poststressing of concrete meets generally accepted engineering practices;

(b) Metallic reinforcing, prestressing wire, structural and nonstructural members used in concrete are acceptable in the installed condition for the temperature and stress levels encountered at design loading conditions; and

(c) Tests for the compressive strength, the coefficient of contraction, an acceptable thermal gradient, and, if applicable, acceptable surface loading to prevent detrimental spalling are performed on the concrete at the lowest temperature for which the concrete is designed or similar test data on these properties are available.

§ 193.2117 Combustible materials.

Combustible materials are not permitted for the construction of buildings, plant equipment, and the foundations and supports of buildings and plant equipment in areas where ignition of the material would worsen an emergency. However, limited combustible materials may be used when the use of noncombustible materials is impractical.

§ 193.2119 Records

Each operator shall keep a record of all materials for components, buildings, foundations, and support systems, as necessary to verify that material properties meet the requirements of this part. These records must be maintained for the life of the item concerned.

Design of Components and Buildings

§ 193.2121 General.

Components, including their foundations and support systems, must be designed, fabricated, and installed to withstand, without loss of functional or structural integrity, predictable loadings not including environmental design forces under Subpart B of this part unless applicable under that subpart.

§ 193.2123 Valves.

(a) Each valve, including control valves and relief valves, must be designed, manufactured, and tested to comply with ANSI B31.3 or ANSI B31.5 or ANSI B31.8 or API Standard 6D, if design conditions fall within their scope.

(b) Extended bonnet valves must be used for service temperatures below −45.6° C (−50° F).

(c) Valves used for cryogenic liquid service must be designed to operate in the position in which they are installed.

(d) Powered local and remote operation must be provided for valves intended for use during a controllable emergency that would be difficult or excessively time-consuming to operate manually during such an emergency.

(e) Valves must be designed and installed so that an excessive load on the piping system does not render the valve inoperable.

§ 193.2125 Automatic shutoff valves.

Each automatic shutoff valve or combination of valves must—

(a) Have a fail-safe design;

(b) Operate to stop fluid flow which would endanger the operational integrity of plant equipment; and

(c) Close at a rate to avoid fluid hammer which would endanger the operating integrity of a component.

§ 193.2127 Piping.

(a) Piping must be designed, manufactured, and tested to comply with ANSI B 31.3.

(b) All cryogenic and hazardous fluid piping must have connections to facilitate blowdown and purge as required by this part.

(c) Each cryogenic or hazardous fluid piping system that is aboveground must be identified by color coding, painting, or labeling.

(d) Seamless pipe or pipe with a longitudinal joint efficienty of 1.0 determined in accordance with ANSI B31.3, or pipe with a design pressure less than two-thirds of the mill-proof test pressure or subsequent shop or field hydrostatic test pressure must be used for process and transfer piping handling cryogenic or other hazardous fluids with a service temperature below −22° F (−30° C).

(e) For longitudinal or spiral weld piping handling LNG or cryogenic fluids, the heat affected zone must comply with § 323.2.2 of ANSI B31.3.

(f) Threaded piping used in hazardous fluid service must be at least Schedule 80.

§ 193.2129 Piping attachments and supports.

Piping attachments and supports for LNG or refrigerant piping must be designed to prevent excessive heat transfer which can result in either unintentional restraint of piping caused by ice formations or the embrittlement of supporting steel.

§ 193.2131 Building design.

(a) Each building or structural enclosure in which potentially hazardous quantities of flammable materials are handled must be designed and constructed to minimize fire hazards.

(b) Buildings or structural enclosures in which hazardous or cryogenic fluids are handled shall be of light-weight, noncombustible construction with nonload-bearings walls.

(c) If rooms containing such fluids are located within or attached to buildings in which such fluids are not handled, i.e., control rooms, shops, etc., the common walls shall be limited to not more than two in number, shall be designed to withstand a static pressure of at least 4800 Pa (100 psf), have no doors or other communicating openings, and shall have a fire resistance rating of at least 1 hour.

§ 193.2133 Buildings; ventilation.

(a) Each building in which potentially hazardous quantities of flammable fluids are handled must be ventilated to minimize the possibility, during normal operation, of hazardous accumulation of a flammable gas and air mixture, hazardous products of combustion, and other hazardous vapors in enclosed process areas by one of the following means:

(1) A continuously operating mechanical ventilation system;

(2) A combination gravity ventilation system and normally off mechanical ventilation system which is activated by suitable flammable gas detectors at a concentration not exceeding 25 percent of the lower flammable limit of the gas;

(3) a dual rate mechanical ventilation system with the high rate activated by suitable flammable gas detectors at a concentration not exceeding 25 percent of the lower flammable limit of the gas; or

(4) A gravity ventilation system composed of a combination of wall openings, roof ventilators, and, if there are basements or depressed floor levels, a supplemental mechanical ventilation system.

(b) The ventilation rate must be at least 1 cubic foot per minute of air per square foot of floor area. If vapors heavier than air can be present, the ventilation must be proportioned according to the area of each level.

§ 193.2135 Expansion or contraction.

Each operator shall consider the amount of contraction and expansion of each component during operating and environmental thermal cycling and shall—

(a) Provide components that operate without detrimental stress or restriction of movement, within each component and between components, caused by contraction and expansion; and

(b) Prevent ice buildup from detrimentally restricting the movement of components caused by contraction and expansion.

§ 193.2137 Frost heave.

(a) Each operator shall—

(1) Determine which components and their foundations could be endangered by frost heave from ambient temperatures or operating temperatures of the component; and

(2) Provide protection against frost heave which might impair their structural integrity.

(b) For each component and foundation determined under paragraph (a) of this section, instrumentation must be installed to warn of potential structural impairment due to frost heave, unless the operator includes in the maintenance procedures required by this part, a method and schedule of inspection that will detect changes in the elevation.

§ 193.2139 Ice and snow.

(a) Components must be designed to support the weight of ice and snow which could normally collect or form on them.

(b) Each operator shall provide protection for components from falling ice or snow which may accumulate on structures.

(c) Valves and moving components must not become inoperative due to ice formation on the component.

§ 193.2141 Electrical systems.

(a) Each operator shall select and install electrical equipment and wiring for components in accordance with NFPA–70 and, where applicable Section 7–62 of NFPA–59A.

(b) Electrical grounding and bonding must be in accordance with Section 7–7.1.1 of NFPA–59A.

(c) Protective measures for stray or impressed currents must be provided in accordance with Section 7–7.3 of NFPA-59A.

§ 193.2143 Lightning.

Each operator shall install proper grounds as necessary to minimize the hazard to plant personnel and components, including all electrical circuits, as a result of lightning.

§ 193.2145 Boilers and pressure vessels.

Boilers must be designed and fabricated in accordance with Section I or Section IV of the ASME Boiler and Pressure Vessel Code. Other pressure vessels subject to that Code must be designed and fabricated in accordance with Division 1 or Division 2 of Section VIII.

§ 193.2147 Combustion engines and turbines.

Combustion engines and gas turbines must be installed in accordance with NFPA–37.

Impoundment Design and Capacity

§ 193.2149 Impoundment required.

(a) An impounding system must be provided for storage tanks to contain a potential spill of LNG or other hazardous liquid.

(b) Grading or drainage or an impounding system must be provided to ensure that accidental spills or leaks from the following components and areas do not endanger components or adjoining property or enter navigable waterways:

(1) Liquefaction and other process equipment;

(2) Vaporizers;

(3) Transfer systems;

(4) Parking areas for tank cars or tank trucks; and

(5) Areas for loading, unloading, or storing portable containers and dewar vessels.

(c) Impounding systems for LNG must be designed and constructed in accordance with this subpart. Impounding systems intended for containment of hazardous liquids other than LNG must meet the requirements of NFPA–30.

§ 193.2151 General design characteristics.

(a) An impounding system must have a configuration or design which, to the maximum extent possible, will prevent liquid from escaping impoundment by leakage, splash from collapse of a structure or part thereof, momentum and low surface friction, foaming, failure of pressurized piping, and accidental pumping.

(b) The basic form of an impounding system may be excavation, a natural geological formation, manufactured diking, such as berms or walls, or any combination thereof.

§ 193.2153 Classes of impounding systems.

(a) For the purpose of this part, impounding systems are classified as follows:

Class 1. A system which surrounds the component served with the inner surface of the dike constructed against or within 24 inches of the component served.

Class 2. A system which surrounds the component or area served with the dike located a distance away from the component or at the periphery of the area.

Class 3. A system which conducts a spill by dikes and floors to a remote impounding space which does not surround the component or area served.

(b) In the case of an impounding system consisting of a combination of classes, requirements of this part regarding a single class apply according to the percentage of impoundment provided by each class.

§ 193.2155 Structural requirements.

(a) Subject to paragraph (b) of this section, the structural parts of an impounding system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of the following:

(1) The imposed loading from—

(i) Full hydrostatic head of impounded LNG;

(ii) Hydrodynamic action, including the effect of any material injected into the system for spill control;

(iii) The impingement of the trajectory of an LNG jet discharged at any predictable angle; and

(iv) Anticipated hydraulic forces from a credible opening in the component or item served, assuming that the discharge pressure equals design pressure.

(2) The erosive action from a spill, including jetting of spilling LNG, and any other anticipated erosive action including surface water runoff, ice formation, dislodgement of ice formation, and snow removal.

(3) The effect of the temperature, any thermal gradient, and any other anticipated degradation resulting from sudden or localized contact with LNG.

(4) Exposure to fire from impounded LNG or from sources other than impounded LNG.

(5) If applicable, the potential impact and loading on the dike due to—

(i) Collapse of the component or item served or adjacent components; and

(ii) If the LNG facility adjoins the right-of-way of any highway or railroad, collision by or explosion of a train, tank car, or tank truck that could reasonably be expected to cause the most severe loading.

(b) For spills from LNG storage tanks with Class 2 or 3 impounding systems, imposed loading and surging flow characteristics must be based on a credible release of the tank contents.

(c) If an LNG storage tank is located within a horizontal distance of 6,100 m. (20,000 ft.) from the nearest point of the nearest runway serving large aircraft as defined in 14 CFR Part 1.1, a Class 1 impounding system must be used which is designed to withstand collision by, or explosion of, the heaviest aircraft which can take off or land at the airport.

§ 193.2157 Coatings and coverings.

Insulation, sealants, or other coatings and coverings which are part of an impounding system—

(a) Must be noncombustible in an installed condition when exposed to an LNG fire resulting from a spill that covers the floor of the impounding space;

(b) Must withstand exposure to fire from sources determined as required by this part, other than impounded LNG, for a period of time until fire protective or fire extinguishing action is taken; and

(c) When used for the purpose of maintaining the functional integrity of an impounding system, must be capable of withstanding sudden exposure to LNG without loss of such integrity.

§ 193.2159 Floors.

Floors of Class 2 and Class 3 impounding systems must, to the extent feasible—

(a) Slope away from the component or item impounded and to a sump basin installed under § 193.2171;

(b) Slope away from the nearest adjacent component;

(c) Drain surface waters from the floor at rates based on a storm of 10-year frequency and 1-hour duration and other natural water sources; and

(d) Be designed to minimize the wetted floor area.

§ 193.2161 Dikes, general.

(a) Penetrations in dikes to accommodate piping or any other purpose are prohibited.

(b) An outer wall of a component served by an impounding system may not be used as a dike except for a concrete wall designed to comply with the requirements of § 193.2155(c) or equivalent design impact loading.

§ 193.2163 Vapor barriers.

If vapor barriers are installed in meeting the requirements of § 193.2059, they must be designed and constructed to detain LNG vapor.

§ 193.2165 Dike dimensions.

In addition to dike dimensions needed to comply with other requirements of this subpart, to minimize the possibility that a trajectory of accidentally discharged liquid would pass over the top of a dike, the horizontal distance from the inner wall of the component or vessel served to the closest inside edge of the top of the dike must at least equal the vertical distance from the maximum liquid level in the component or vessel to the inside edge of the top of the dike.

§ 193.2167 Covered systems.

(a) A covered impounding system is prohibited unless it is—

(1) Sealed from the atmosphere and filled with an inert gas; or

(2) Permanently interconnected with the vapor space of the component served.

(b) Flammable nonmetallic membranous covering is prohibited in a covered system.

(c) For systems to which paragraph (a)(1) of this section applies, instrumentation and controls must be provided to—

(1) Maintain pressures at a safe level; and

(2) Monitor gas concentrations in accordance with § 193.2169.

(d) Dikes must have adequate structural strength to assure that they can withstand impact from a collapsed cover and all anticipated conditions which could cause a failure of the impounding space cover.

§ 193.2169 Gas leak detection.

Appropriate areas within an impounding system where collection or passage of LNG or LNG vapor could be expected must be equipped with sensing and warning devices to monitor continuously for the presence of LNG or LNG vapor and to warn before LNG gas concentration levels exceed 25 percent of the lower flammable limit.

§ 193.2171 Sump basins.

Except for Class 1 impounding systems, a sump basin must be located in each impounding system for collection of water.

§ 193.2173 Water removal.

(a) Except for Class 1 systems, impounding systems must have sump pumps and piping running over the dike to remove water collecting in the sump basin.

(b) The water removal system must have adequate capacity to remove water at rates which equal the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration, and other natural causes.

(c) Sump pumps for water removal must—

(1) Be operated as necessary to keep the impounding space as dry as practical; and

(2) If sump pumps are designed for automatic operation, have redundant automatic shutdown controls to prevent operation when LNG is present.

§ 193.2175 Shared impoundment.

When an impounding system serves more than one LNG storage tank, a means must be provided to prevent low temperature or fire resulting from leakage from any one of the storage tanks served causing any other storage tank to leak. The means must not result in a vapor dispersion distance which exceeds the exclusion zone required by § 193.2059.

§ 193.2179 Impoundment capacity; general.

In addition to capacities otherwise required by this subpart, an impounding system must have sufficient volumetric capacity to provide for—

(a) Displacement by the component, tank car, tank truck, container, or dewar vessel served; and

(b) Where applicable, displacement which could occur when a higher density substance than the liquid to be impounded enters the system, considering all relevant means of assuring capacity.

§ 193.2181 Impoundment capacity, LNG storage tanks.

(a) Except as provided in paragraph (b) of this section, each impounding system serving an LNG storage tank must have a minimum volumetric liquid impoundment capacity as follows:

Number of tanks in system	Class or type of system	System capacity in percent of LNG tank's maximum liquid capacity
1	Class 1	110 percent.
	Classes 2 and 3	150 percent.
More than 1	Classes 2 and 3	100 percent of all tanks or 150 percent of largest tank, whichever is greater.

(b) For purposes of this section, a covered impounding system serving a single LNG storage tank may have a capacity of 110 percent of the LNG tank's maximum liquid capacity if it is covered by a roof that is separate and independent from the LNG storage tank.

§ 193.2183 Impoundment capacity; equipment and transfer systems.

If an impounding system serves a component under § 193.2149(b) (1)–(3), it must have a minimum volumetric liquid impoundment capacity equal to the sum of—

(a) One-hundred percent of the volume of liquid that could be contained in the component and, where applicable, tank car or tank truck served; and

(b) The maximum volume of liquid which could discharge into the impounding space from any single failure of equipment or piping during the time period necessary for spill detection, instrument response, and sequenced shutdown by the automatic shutdown system under § 193.2439.

§ 193.2185 Impoundment capacity; parking areas, portable containers.

Each impounding system serving an area listed under § 193.2149(b) (4) or (5) must have a minimum volumetric liquid impoundment capacity which complies with the requirements of § 193.2181, assuming each tank car, tank truck, portable container, or dewar vessel to be a storage tank.

LNG Storage Tanks

§ 193.2187 General.

(a) LNG storage tanks must comply with the requirements of this subpart and the other applicable requirements of this part.

(b) A flammable nonmetallic membrane liner may not be used as an inner container in a storage tank.

§ 193.2189 Loading forces.

Each part of an LNG storage tank must be designed to withstand without loss of functional or structural integrity any predictable combination of forces which would result in the highest stress to the part, including the following:

(a) Internal design pressure determined under § 193.2197.

(b) External design pressure determined under § 193.2199.

(c) Weight of the structure.

(d) Weight of liquid to be stored, except that in no case will the density assumed be less than 29.3 pounds per cubic foot (470 kilograms per cubic meter).

(e) Loads due to testing required by § 193.2327.

(f) Nonuniform reaction forces on the foundation due to predictable settling and other movement.

(g) Superimposed forces from piping, stairways, and other connected appurtenances.

(h) Predictable snow and ice loads.

(i) The loading of internal insulation on the inner container and outer shell due to compaction and movement of the container and shell over the design life of the insulation.

(j) In the case of vacuum insulation, the forces due to the vacuum.

(k) In the case of a positive pressure purge, the forces due to the maximum positive pressure of the purge gas.

§ 193.2191 Stratification.

LNG storage tanks with a capacity of 5,000 barrels or more must be equipped with means to mitigate a potential for rollover and overpressure such as:

(a) Selective filling at the top and bottom of the tank;

(b) Circulating liquid from the bottom to the top of the same tank; or

(c) Transferring liquid selectively from the bottom of the tank to the bottom or top of any adjacent storage tank.

§ 193.2193 Movement and stress.

(a) Each operator shall determine for normal operations of each LNG storage tank—

(1) The amount and pattern of predictable movement of components, including transfer piping, and the foundation, which could result from thermal cycling, loading forces, and ambient air changes; and

(2) For a storage tank with an inner container, the predictable movement of the inner container and the outer shell in relation to each other.

(b) Storage tanks must be designed to provide adequate allowance for stress due to movement determined under paragraph (a) of this section, including provisions that—

(1) Backfill does not cause excessive stresses on the tank structure due to expansion of the storage tank during warmup;

(2) Insulation does not settle to a damaging degree or unsafe condition during thermal cycling; and

(3) Expansion bends and other expansion or contraction devices are adequate to prevent excessive stress on tank penetrations, especially during cooldown from ambient temperatures.

§193.2195 Penetrations.

(a) All penetrations in an LNG storage tank must be designed in accordance with API 620, including Appendix Q.

(b) The loadings on all penetrations must be determined by an analysis of all contributing forces, including those from tank thermal movements, connecting piping thermal movements, hydraulic forces, applicable wind and earthquake forces, and the forces resulting from settlement or movement of the tank foundation or pipe supports.

(c) All penetrations in an LNG storage tank below the design liquid level must be fitted with an internal shutoff valve which is designed and installed so that any failure of the nozzle penetrating the tank will be outside the tank.

(d) The requirements of paragraphs (a) and (c) of this section do not apply to shop fabricated tanks of 70,000 gallons or less capacity. All penetrations in such tanks must be designed and installed in accordance with the applicable provisions of Section VIII, Division 1 of the ASME Boiler and Pressure Vessel Code.

§ 193.2197 Internal design pressure.

(a) Each operator shall establish the internal design pressure at the top of each LNG storage tank, including a suitable margin above the maximum allowable working pressure.

(b) The internal design pressure of a storage tank may not be lower than the highest pressure in the vapor space resulting from each of the following events or combination thereof that predictably might occur, giving consideration to vapor handling equipment, relief devices in accordance with § 193.2429, and any other mitigating measures:

(1) Filling the tank with LNG including effects of increased vaporization rate due to superheat and sensible heat of the added liquid;

(2) Rollover.

(3) Fall in barometric pressure, using the worst combination of amount of fall and rate of fall which might predictably occur;

(4) Loss of effective insulation that may result from an adjacent fire, leak of liquid into the intertank space, or other predictable accident; and

(5) Flash vaporization resulting from pump recirculation.

§ 193.2199 External design pressure.

(a) Each operator shall establish the external design pressure at the top of each LNG storage tank, including a suitable margin below the minimum allowable working pressure.

(b) The external design pressure may not be higher than the lowest vapor pressure in the vapor space resulting from each of the following events or combinations thereof that predictably might occur, giving consideration to gas makeup systems, vacuum relief devices in accordance with § 193.2429, and any other mitigating measures.

(1) Withdrawing liquid from the tank;

(2) Withdrawing gas from the tank;

(3) Adding subcooled LNG to the tank; and

(4) Rise in barometric pressure, based on the worst combination of amount of rise and rate of rise which predictably might occur.

§ 193.2201 Internal temperature.

The liquid container of each LNG storage tank and all tank parts used in contact with LNG or its cold vapor shall be designed for the lowest bulk liquid temperature which can be attained in the LNG storage tank.

§ 193.2203 Foundation.

(a) Each LNG storage tank must have a stable foundation designed in accordance with generally accepted structural engineering practices.

(b) Each foundation must support design loading forces without detrimental settling that could impair the structural integrity of the tank.

§ 193.2205 Frost heave.

If the protection provided for LNG storage tank foundations from frost heave under § 193.2137(a) includes heating the foundation area—

(a) An instrumentation and alarm system must be provided to warn of malfunction of the heating system; and

(b) A means to correct the malfunction must be provided.

§ 193.2207 Insulation.

(a) Insulation on the outside of the outer shell of an LNG storage tank may not be used to maintain stored LNG at an operating temperature during normal operation.

(b) Insulation between an inner container and the outer shell of an LNG storage tank must—

(1) Be compatible with the contained liquid and its vapor;

(2) In its installed condition, be noncombustible; and

(3) Not significantly lose insulating properties by melting, settling, or other means due to a fire resulting from a spill that covers the floor of the impounding space around the tank.

§ 193.2209 Instrumentation for LNG storage tanks.

(a) Each LNG storage tank having a capacity over 70,000 gallons must be equipped with a sufficient number of sensing devices and personnel warning devices, as prescribed, which operate continuously while the tank is in operation to assure that each of the following conditions is not a potential hazard to the structural integrity or safety of the tank:

Condition	Instrumentation
(1) Amount of liquid in the tank.	Redundant liquid level gages and recorders with high level alarms, and a minimum of one independent high level alarm.
(2) Vapor pressure within the tank.	Redundant gages and recorders with high and low pressure alarms.
(3) Temperatures at representative critical points in the foundation.	Temperature indicating and recording devices with alarm.
(4) Temperature of contained liquid at various vertical intervals.	Temperature recorders.
(5) Abnormal temperature in tank structure.	Thermocouples located at representative critical points with recorders.
(6) Excessive relative movement of inner container and outer shell.	Linear and rotational movement indicators located between inner container and outer shell with recorders.

(b) LNG storage tanks with a capacity of 70,000 gallons or less must be equipped with the following:

(1) LNG liquid trycocks, when attended during the filling operation.

(2) Pressure gages and recorders with high pressure alarm.

(3) Differential pressure liquid level gage.

(c) Each storage tank must be designed as appropriate to provide for compliance with the inspection requirements of this part.

§ 193.2211 Metal storage tanks.

(a) Metal storage tanks with internal design pressures of not more than 15 psig must be designed and constructed in accordance with API Standard 620 and, where applicable, Appendix Q of that standard.

(b) Metal storage tanks with internal design pressures above 15 psig must be designed in accordance with the applicable division of Section VIII of the ASME Boiler and Pressure Vessel Code.

§ 193.2213 Concrete storage tanks.

Concrete storage tanks must be designed and constructed in accordance with Section 4–3 of NFPA–59A.

§ 193.2215 Thermal barriers.

Thermal barriers must be provided between piping and an outer shell when necessary to prevent the outer shell from being exposed during normal operation to temperatures lower than its design temperature.

§ 193.2217 Support system.

(a) Saddles and legs must be designed in accordance with generally accepted structural engineering practices, taking into account loads during transportation, erection loads, and thermal loads.

(b) Storage tank stress concentrations from support systems must be minimized by distribution of loads using pads, load rings, or other means.

(c) For a storage tank with an inner container, support systems must be designed to—

(1) Minimize thermal stresses imparted to the inner container and outer shell from expansion and contraction; and

(2) Sustain the maximum applicable loading from shipping and operating conditions.

(d) LNG storage tanks with an air space beneath the tank bottom or its foundation must be designed to withstand without loss of functional or structural integrity, the forces caused by the ignition of a combustible vapor cloud in this space.

§ 193.2219 Internal piping.

Piping connected to an inner container that is located in the space between the inner container and outer shell must be designed for not less than the pressure rating of the inner container. The piping must contain expansion loops where necessary to protect against thermal and other secondary stresses created by operation of the tank. Bellows may not be used within the space between the inner container and outer shell.

§ 193.2221 Marking.

(a) Each operator shall install and maintain a name plate in an accessible place on each storage tank and mark it in accordance with the applicable code or standard incorporated by reference in §§ 193.2211 or 193.2213.

(b) Each penetration in a storage tank must be marked indicating the function of the penetration.

(c) Marking required by this section must not be obscured by frosting.

Design of Transfer Systems

§ 193.2223 General.

(a) Transfer systems must comply with the requirements of this subpart and other applicable requirements of this part.

(b) The design of transfer systems must provide for stress due to the frequency of thermal cycling and intermittent use to which the transfer system may be subjected.

(c) Slip type expansion joints are prohibited and packing-type joints may not be used in transfer systems for LNG or flammable refrigerants.

(d) A suitable means must be provided to precool the piping in a manner that prevents excessive stress prior to normal transfer of cold fluids.

(e) Stresses due to thermal and hydraulic shock in the piping system must be determined and accommodated by design to avoid damage to piping.

§ 193.2227 Backflow.

(a) Each transfer system must operate with a means to—

(1) Prevent backflow of liquid from a receiving container, tank car, or tank truck from causing a hazardous condition; and

(2) Maintain one-way flow where necessary for the integrity or safe operation of the LNG facility.

(b) The means provided under paragraph (a)(1) of this section must be located as close as practical to the point of connection of the transfer system and the receiving container, tank car, or tank truck.

§ 193.2229 Cargo transfer systems.

(a) Each cargo transfer system must have—

(1) A means of safely depressurizing and venting that system before disconnection;

(2) A means to provide for safe vapor displacement during transfer;

(3) Transfer piping, pumps, and compressors located or protected by suitable barriers so that they are safe from damage by tank car or tank truck movements;

(4) A signal light at each control location or remotely located pumps or compressors used for transfer which indicates whether the pump or compressor is off or in operation; and

(5) A means of communication between loading or unloading areas and other areas in which personnel are associated with the transfer operations.

(b) Hoses and arms for cargo transfer systems must be designed as follows—

(1) The design must accommodate operating pressures and temperatures encountered during the transfers;

(2) Hoses must have a bursting pressure of not less than five times the operating pressure.

(3) Arms must meet the requirements of ANSI B31.3.

(4) Adequate support must be provided, taking into account ice formation.

(5) Couplings must be designed for the frequency of any coupling or uncoupling.

§ 193.2231 Cargo transfer area.

The transfer area of a cargo transfer system must be designed—

(a) To accommodate tank cars and tank trucks without excessive maneuvering; and

(b) To permit tank trucks to enter or exit the transfer area without backing.

§ 193.2233 Shutoff valves.

(a) Shutoff valves on transfer systems must be located—

(1) On each liquid supply line, or common line to multiple supply lines, to a storage tank, or to a cargo transfer system;

(2) On each vapor or liquid return line from multiple return lines, used in a cargo transfer system;

(3) At the connection of a transfer system with a pipeline subject to Part 192 of this chapter; and

(4) To provide for proper operation and maintenance of each transfer system.

(b) Transfer system shutoff valves that are designated for operation in the emergency procedures must be manually operable at the valve and power operable at the valve and at a remote location at least 50 feet from the valve.

Subpart D—Construction

§ 193.2301 Scope.

This subpart prescribes requirements for the construction or installation of components.

§ 193.2303 Construction acceptance.

No person may place in service any component until it passes all applicable inspections and tests prescribed by this subpart.

§ 193.2304 Corrosion control overview.

(a) Subject to paragraph (b) of this section, components may not be constructed, repaired, replaced, or significantly altered until a person qualified under § 193.2707(c) reviews the applicable design drawings and materials specifications from a corrosion control viewpoint and determines that the materials involved will not impair the safety or reliability of the component or any associated components.

(b) The repair, replacement, or significant alteration of components must be reviewed only if the action to be taken—

(1) Involves a change in the original materials specified;

(2) Is due to a failure caused by corrosion; or

(3) Is occasioned by inspection revealing a significant deterioration of the component due to corrosion.

§ 193.2305 Procedures.

(a) In performing construction, installation, inspection, or testing, an operator must follow written specifications, procedures, and drawings, as appropriate, that are consistent with this part, taking into account relevant mechanical, chemical, and thermal properties, component functions, and environmental effects that are involved.

(b) All procedures, including any field revisions, must be substantiated by testing or experience to produce a component that is reliable and complies with the design and installation requirements of this part.

§ 193.2307 Inspection.

(a) All construction, installation, and testing activities must be inspected as frequently as necessary in accordance with a written plan to assure that—

(1) Activities are in compliance with all applicable requirements of this subpart; and

(2) Components comply with the applicable material, design, fabrication, installation, and construction requirements of this part.

(b) In addition to the requirements of paragraph (a) of this section, the construction of concrete storage tanks must be inspected in accordance with ACI–311–75.

(c) Each operator shall have a quality assurance inspection program to verify that components comply with their design specifications and drawings, including any field design changes, before they are placed in service.

§ 193.2309 Inspection and testing methods

Except as otherwise provided by this subpart, each operator shall determine, commensurate with the hazard that would result from failure of the component concerned, the scope and nature of—

(a) Inspections and tests required by this subpart; and

(b) Inspection and testing procedures required by § 193.2305.

§ 193.2311 Cleanup.

After construction or installation, as the case may be, all components must be cleaned to remove all detrimental contaminants which could cause a hazard during operation, including the following:

(a) All flux residues used in brazing or soldering must be removed from the joints and the base metal to prevent corrosive solutions from being formed.

(b) All solvent type cleaners must be tested to ensure that they will not damage equipment integrity or reliability.

(c) Incompatible chemicals must be removed.

(d) All contaminants must be captured and disposed of in a manner that does not reduce the effectiveness of corrosion protection and monitoring provided as required by this part.

§ 193.2313 Pipe welding.

(a) Each operator shall provide the following for welding on pressurized piping for LNG and other hazardous fluids:

(1) Welding procedures and welders qualified in accordance with Section IX of the ASME Boiler and Pressure Vessel Code or API 1104, as applicable;

(2) When welding materials that are qualified by impact testing, welding procedures selected to minimize degradation of low temperature properties of the pipe material; and

(3) When welding attachments to pipe, procedures and techniques selected to minimize the danger of burn-throughs and stress intensification.

(b) Oxygen fuel gas welding is not permitted on flammable fluid piping with a service temperature below −20°C (−22°F).

(c) Marking materials for identifying welds on pipe must be compatible with the basic pipe material.

(d) Surfaces of components that are less than 6.35 mm (0.25 in.) thick may not be field die stamped.

(e) Where die stamping is permitted, any identification marks must be made with a die having blunt edges to minimize stress concentration.

§ 193.2315 Piping connections.

(a) Piping more than 2 inches nominal diameter must be joined by welding, except that—

(1) Threaded or flanged connections may be used where necessary for special connections, including connections for material transitions, instrument connections, testing, and maintenance;

(2) Copper piping in nonflammable service may be joined by silver brazing; and

(3) Material transitions may be made by any joining technique proven reliable under § 193.2305(b).

(b) If socket fittings are used, a clearance of 1.6 to 3.2 mm (0.063 to 0.126 in.) between the pipe end and the bottom of the socket recess must be provided and appropriate measurement reference marks made on the piping for the purpose of inspection.

(c) Threaded joints must be—

(1) Free of stress from external loading; and

(2) Seal welded, or sealed by other means which have been tested and proven reliable.

(d) Compression type couplings must meet the requirements of ANSI B31.3.

(e) Care shall be taken to ensure the tightness of all bolted connections. Spring washers or other such devices designed to compensate for the contraction and expansion of bolted connections during operating cycles shall be used where required.

(f) The selection of gasket material shall include the consideration of fire.

§ 193.2317 Retesting.

After testing required by this subpart is completed on a component to contain a hazardous fluid, the component must be retested whenever—

(a) Penetration welding other than tie-in welding is performed; or

(b) The structural integrity of the component is disturbed.

§ 193.2319 Strength tests.

(a) A strength test must be performed on each piping system and container to determine whether the component is capable of performing its design function, taking into account—

(1) The maximum allowable working pressure;

(2) The maximum weight of product which the component may contain or support;

(b) For piping, the test required by paragraph (a) of this section must include a pressure test conducted in accordance with Section 337 of ANSI B31.3, except that test pressures must be based on the design pressure. Carbon and low alloy steel piping must be pressure tested above their nil ductility transition temperature.

(c) All shells and internal parts of heat exchangers to which Section VIII, Division 1, or Division 2 of the ASME Boiler and Pressure Vessel Code, applies must be pressure tested, inspected, and stamped in accordance therewith.

§ 193.2321 Nondestructive tests.

(a) The following percentages of each day's circumferentially welded pipe joints for hazardous fluid piping, selected at random, must be nondestructively tested over the entire circumference to indicate any defects which could adversely affect the integrity of the weld or pipe:

Weld type	Cryogenic piping	Other	Test method
Butt weld more than 2 inches in nominal size.	100	30	Radiographic or ultrasonic.
Butt welds 2 inches or less in nominal size.	100	30	Radiographic, ultrasonic, liquid penetrant, or magnetic particle.
Fillet and socket welds.	100	30	Liquid penetrant or magnetic particle.

(b) Evaluation of weld tests and repair of defects must be in accordance with the requirements of ANSI B31.3 or API 1104, as applicable.

(c) Where longitudinally or spiral welded pipe is used in transfer systems, 100 percent of the seam weld must be examined by radiographic or ultrasonic inspection.

(d) The butt welds in metal shells of storage tanks with internal design pressure of not more than 15 psig must be radiographically tested in accordance with Section 0.7.6, API 620, Appendix Q, except that for hydraulic load bearing shells with curved surfaces that are subject to cryogenic temperatures, 100 percent of both longitudinal (or meridional) and circumferential or (or latitudinal) welds must be radiographically tested.

(e) The butt welds in metal shells of storage tanks with internal design pressure above 15 psig must be radiographically tested in accordance with Section IX of the ASME Boiler and Pressure Vessel Code, except that for hydraulic load bearing shells with curved surfaces that are subject to cryogenic temperatures, 100 percent of both longitudinal (or meridional) and circumferential (or latitudinal) welds must be radiographically tested.

§ 193.2323 Leak tests.

(a) Each container and piping system must be initially tested to assure that the component will contain the product for which it is designed without leakage.

(b) Shop fabricated containers and all flammable fluid piping must be leak tested to a minimum of the design pressure after installation but before placing it in service.

(c) For a storage tank with vacuum insulation, the inner container, outer shell, and all internal piping must be tested for vacuum leaks in accordance with an appropriate procedure.

§ 193.2325 Testing control systems.

Each control system must be tested before being placed in service to assure that it has been installed properly and will function as required by this part.

§ 193.2327 Storage tank tests.

(a) In addition to other applicable requirements of this subpart, storage tanks for cryogenic fluids with internal design pressures of not more than 15 psig must be tested in accordance with Sections Q8 and Q9 of API 620, Appendix Q, as applicable.

(b) Metal storage tanks for cryogenic fluids with internal design pressures above 15 psig must be tested in accordance with the applicable division of Section VIII of the ASME Boiler and Pressure Vessel Code.

(c) Reference measurements must be made with appropriate precise instruments to assure that the tank is gas tight and lateral and vertical movement of the storage tank does not exceed predetermined design tolerances.

§ 193.2329 Construction records.

For the service life of the component concerned, each operator shall retain appropriate records of the following:

(a) Specifications, procedures, and drawings prepared for compliance with § 193.2305; and

(b) Results of tests, inspections, and the quality assurance program required by this subpart.

Subpart E—Equipment

§ 193.2401 Scope.

This subpart prescribes requirements for the design, fabrication, and installation of vaporization equipment, liquefaction equipment, and control systems.

Vaporization Equipment

§ 193.2403 General.

Vaporizers must comply with the requirements of this subpart and the other applicable requirements of this part.

§ 193.2405 Vaporizer design.

(a) Vaporizers must be designed and fabricated in accordance with applicable provisions of Section VIII, Division 1 of the ASME Boiler and Pressure Vessel Code.

(b) Each vaporizer must be designed for the maximum allowable working pressure at least equal to the maximum discharge pressure of the pump or pressurized container system supplying it, whichever is greater.

§ 193.2407 Operational control.

(a) Vaporizers must be equipped with devices which monitor the inlet pressure of the LNG, the outlet temperature, and the pressure of the vaporized gas, and the inlet pressure of the heating medium fluids.

(b) Manifolded vaporizers must be equipped with:

(1) Two inlet valves in series to prevent LNG from entering an idle vaporizer; and

(2) A means to remove LNG or gas which accumulates between the valves.

§ 193.2409 Shutoff valves.

(a) A shutoff valve must be located on transfer piping supplying LNG to a vaporizer. The shutoff valve must be located at a sufficient distance from the vaporizer to minimize potential for damage from explosion or fire at the vaporizer. If the vaporizer is installed in a building, the shutoff valve must be located outside the building.

(b) A shutoff valve must be located on each outlet of a vaporizer.

(c) For vaporizers designed to use a flammable intermediate fluid, a shutoff valve must be located on the inlet and outlet line of the intermediate fluid piping system where they will be operable during a controllable emergency involving the vaporizer.

§ 193.2411 Relief devices.

The capacity of pressure relief devices required for vaporizers by § 193.2429 is governed by the following:

(a) For heated vaporizers, the capacity must be at least 110 percent of rated natural gas flow capacity without allowing the pressure to rise more than 10 percent above the vaporizer's maximum allowable working pressure.

(b) For ambient vaporizers, the capacity must be at least 150 percent of rated natural gas flow capacity without allowing the pressure to rise more than 10 percent above the vaporizer's maximum allowable working pressure.

§ 193.2413 Combustion air intakes.

(a) Combustion air intakes to vaporizers must be equipped with sensing devices to detect the induction of a flammable vapor.

(b) If a heated vaporizer or vaporizer heater is located in a building, the combustion air intake must be located outside the building.

Liquefaction Equipment

§ 193.2415 General.

Liquefaction equipment must comply with the requirements of this subpart and the other applicable requirements of this part.

§ 193.2417 Control of incoming gas.

A shutoff valve must be located on piping delivering natural gas to each liquefaction system.

§ 193.2419 Backflow.

Each multiple parallel piping system connected to liquefaction equipment must have devices to prevent backflow from causing a hazardous condition.

§ 193.2421 Cold boxes.

(a) Each cold box in a liquefaction system must be equipped with a means of monitoring or detecting, as appropriate, the concentration of natural gas in the insulation space.

(b) If the insulation space in a cold box is designed to operate with a gas rich atmosphere, additional natural gas must be introduced when the concentration of gas falls to 30 percent.

(c) If the insulation space of a cold box is designed to operate with a gas free atmosphere, additional air or inert gas, as appropriate, must be introduced when the concentration of gas is 25 percent of the lower flammable limit.

§ 193.2423 Air in gas.

Where incoming gas to liquefaction equipment contains air, each operator shall provide a means of preventing a flammable mixture from occurring under any operating condition.

Control Systems

§ 193.2427 General.

(a) Control systems must comply with the requirements of this subpart and other applicable requirements of this part.

(b) Each control system must be capable of performing its design function under normal operating conditions.

(c) Control systems must be designed and installed in a manner to permit maintenance, including inspection or testing, in accordance with this part.

(d) Local, remote, and redundant signal lines installed for control systems that can affect the operation of a component that does not fail safe must be routed separately or in separate underground conduits installed in accordance with NFPA-70.

§ 193.2429 Relief devices.

(a) Each component containing a hazardous fluid must be equipped with a system of automatic relief devices which will release the contained fluid at a rate sufficient to prevent pressures from exceeding 110 percent of the maximum allowable working pressure. In establishing relief capacity, each operator shall consider trapping of fluid between valves; the maximum rates of boiloff and expansion of fluid which may occur during normal operation, particularly cooldown; and controllable emergencies.

(b) A component in which internal vacuum conditions can occur must be equipped with a system of relief devices or other control system to prevent development in the component of a vacuum that might create a hazardous condition. Introduction of gas into a component must not create a flammable mixture within the component.

(c) In addition to the control system required by paragraphs (a) and (b) of this section—

(1) Each LNG Storage tank must be equipped with relief devices to assure that design pressure and vacuum relief capacity is available during maintenance of the system; and

(2) A manual means must be provided to relieve pressure and vacuum in an emergency.

(d) Relief devices must be installed in a manner to minimize the possibility that release of fluid could—

(1) Cause an emergency; or

(2) Worsen a controllable emergency.

(e) The means for adjusting the setpoint pressure of all adjustable relief devices must be sealed.

(f) Relief devices which are installed to limit minimum or maximum pressure may not be used to handle boiloff and flash gases during normal operation.

§ 193.2431 Vents.

(a) Hazardous fluids may not be relieved into the atmosphere of a building or other confined space.

(b) Boiloff vents for hazardous fluids may not draw in air during operation.

(c) Venting of natural gas/vapor under operational control which could produce a hazardous gas atmosphere must be directed to a flare stack or heat exchanger in order to raise its temperature to achieve positive buoyancy and safe venting.

§ 193.2433 Sensing devices.

(a) Each operator shall determine the appropriate location for and install sensing devices as necessary to—

(1) Monitor the operation of components to detect a malfunction which could cause a hazardous condition if permitted to continue; and

(2) Detect the presence of fire or combustible gas in areas determined in accordance with Section 500–4 of NFPA 70 to have a potential for the presence of flammable fluids.

(b) Buildings in which potentially hazardous quantities of flammable fluids are used or handled must be continuously monitored by gas sensing devices set to activate audible and visual alarms in the building and at the control center when the concentration of the fluid in air is not more than 25 percent of the lower flammable limit.

§ 193.2435 Warning devices.

Each operator shall install warning devices in the control center to warn of hazardous conditions detected by all sensing devices required by this part. Warnings must be given both audibly and visibly and must be designed to gain the attention of personnel. Warnings must indicate the location and nature of the existing or potential hazard.

§ 193.2437 Pump and compressor control.

(a) Each pump and compressor for hazardous fluids must be equipped with—

(1) A control system, operable locally and remotely, to shut down the pump or compressor in a controllable emergency;

(2) A signal light at the pump or compressor and the remote control location which indicates whether the pump or compressor is in operation or off;

(3) Adequate valving to ensure that the pump or compressor can be isolated for maintenance; and

(4) A check valve on each discharge line where pumps or compressors operate in parallel.

(b) Pumps or compressors in a cargo transfer system must have shutdown controls at the loading or unloading area and at the pump or compressor site.

§ 193.2439 Emergency shutdown control systems.

(a) Each transfer system, vaporizer, liquefaction system, and storage system tank must be equipped with an emergency shutdown control system. The control must automatically actuate the shutdown of the component (providing pressure relief as necessary) when any of the following occurs:

(1) Temperatures of the component exceed the limits determined under § 193.2105;

(2) Pressure outside the limits of the maximum and minimum design pressure;

(3) Liquid in receiving vessel reaches the design maximum liquid level;

(4) Gas concentrations in the area of the component exceed 40 percent of the lower flammable limit;

(5) A sudden excessive pressure change or other condition indicating a potentially dangerous condition; and

(6) Presence of fire in area of component.

(b) For cargo transfer systems where all transfer operations are continuously manned and visually supervised by qualified personnel, actuation of the emergency shutdown control system may be manual after devices warn of the events listed in paragraph (a) of this section.

(c) Except for components that operate unattended and are remote from the control center, a reasonable delay may be programmed in emergency shutdown control systems required by this section between warning and automated shutdown to provide for manual response.

(d) Each LNG plant must have a shutdown control system to shut down all operations of the plant safely. The system must be operable at—

(1) The control center; and

(2) In the case of a plant where LNG facilities other than the control center are designed to operate unattended at the site of these facilities.

§ 193.2441 Control center.

Each LNG plant must have a control center from which operations and warning devices are monitored as required by this part. A control center must have the following capabilities and characteristics—

(a) It must be located apart or protected from other LNG facilities so that it is operational during a controllable emergency.

(b) Each remotely actuated control system and each automatic shutdown control system required by this part must be operable from the control center.

(c) Each control center must have personnel in continuous attendance while any of the components under its control are in operation, unless the control is being performed from another control center which has personnel in continuous attendance.

(d) If more than one control center is located at an LNG Plant, each control center must have more than one means of communication with each other center.

(e) Each control center must have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel.

§ 193.2443 Fail-safe control.

Control systems for components must have a fail-safe design. A safe condition must be maintained until personnel take appropriate action either to reactivate the component served or to prevent a hazard from occurring.

§ 193.2445 Sources of power.

(a) Electrical control systems, means of communication, emergency lighting, and firefighting systems must have at least two sources of power which function so that failure of one source does not affect the capability of the other source.

(b) Where auxiliary generators are used as a second source of electrical power—

(1) They must be located apart or protected from components so that they are not unusable during a controllable emergency; and

(2) Fuel supply must be protected from hazards.

Subpart F—Operations

§ 193.2501 Scope.

This subpart prescribes requirements for the operation of LNG facilities.

§ 193.2503 Operating procedures.

Each operator shall follow one or more manuals of written procedures to provide safety in normal operation and in responding to an abnormal operation that would affect safety. The procedures must include provisions for—

(a) Monitoring components or buildings according to the requirements of § 193.2507.

(b) Startup and shutdown, including for initial startup, performance testing to demonstrate that components will operate satisfactory in service.

(c) Recognizing abnormal operating conditions.

(d) Purging and inerting components according to the requirements of § 193.2517.

(e) In the case of vaporization, maintaining the vaporization rate, temperature and pressure so that the resultant gas is within limits established for the vaporizer and the downstream piping;

(f) In the case of liquefaction, maintaining temperatures, pressures, pressured differentials and flow rates, as applicable, within their design limits for:

(1) Boilers;

(2) Turbines and other prime movers;

(3) Pumps, compressors, and expanders;

(4) Purification and regeneration equipment; and

(5) Equipment within cold boxes.

(g) Cooldown of components according to the requirements of § 193.2505; and

(h) Compliance with § 193.2805(b).

§ 193.2505 Cooldown.

(a) The cooldown of each system of components that is subjected to cryogenic temperatures must be limited to a rate and distribution pattern that keeps thermal stresses within design limits during the cooldown period, paying particular attention to the performance of expansion and contraction devices.

(b) After cooldown stabilization is reached, cryogenic piping systems must be checked for leaks in areas of flanges, valves, and seals.

§ 193.2507 Monitoring operations.

Each component in operation or building determined under § 193.2805(a)(2) in which a hazard to persons or property could exist must be monitored to detect fire or any malfunction or flammable fluid which could cause a hazardous condition. Monitoring must be accomplished by watching or listening from an attended control center for warning alarms, such as gas, temperature, pressure, vacuum, and flow alarms, or by conducting an inspection or test at intervals specified in the operating procedures.

§ 193.2509 Emergency procedures.

(a) Each operator shall determine the types and places of emergencies other than fires that may reasonably be expected to occur at an LNG plant due to operating malfunctions, structural collapse, personnel error, forces of nature, and activities adjacent to the plant.

(b) To adequately handle each type of emergency identified under paragraph (a) of this section and each fire emergency identified under § 193.2817(a), each operator shall follow one or more manuals of written procedures. The procedures must provide for the following:

(1) Responding to controllable emergencies, including notifying personnel and using equipment appropriate for handling the emergency.

(2) Recognizing an uncontrollable emergency and taking action to minimize harm to the public and personnel, including prompt notification of appropriate local officials of the emergency and possible need for evacuation of the public in the vicinity of the LNG plant.

(3) Coordinating with appropriate local officials in preparation of an emergency evacuation plan, which sets forth the steps required to protect the

public in the event of an emergency, including catastrophic failure of an LNG storage tank.

(4) Cooperating with appropriate local officials in evacuations and emergencies requiring mutual assistance and keeping these officials advised of—

(i) The LNG plant fire control equipment, its location, and quantity of units located throughout the plant;

(ii) Potential hazards at the plant, including fires;

(iii) Communication and emergency control capabilities at the LNG plant; and

(iv) The status of each emergency.

§ 193.2511 Personnel safety.

(a) Each operator shall provide any special protective clothing and equipment necessary for the safety of personnel while they are performing emergency response duties.

(b) All personnel who are normally on duty at a fixed location, such as a building or yard, where they could be harmed by thermal radiation from a burning pool of impounded liquid, must be provided a means of protection at that location from the harmful effects of thermal radiation or a means of escape.

(c) Each LNG plant must be equipped with suitable first-aid material, the location of which is clearly marked and readily available to personnel.

§ 193.2513 Transfer procedures.

(a) Each transfer of LNG or other hazardous fluid must be conducted in accordance with one or more manuals of written procedures to provide for safe transfers.

(b) The transfer procedures must include provisions for personnel to:

(1) Before transfer, verify that the transfer system is ready for use, with connections and controls in proper positions, including if the system could contain a combustible mixture, verifying that it has been adequately purged in accordance with a procedure which meets the requirements of AGA "Purging Principles and Practice."

(2) Before transfer, verify that each receiving container or tank vehicle does not contain any substance that would be incompatible with the incoming fluid and that there is sufficient capacity available to receive the amount of fluid to be transferred;

(3) Before transfer, verify the maximum filling volume of each receiving container or tank vehicle to ensure that expansion of the incoming fluid due to warming will not result in overfilling or overpressure;

(4) When making bulk transfer of LNG into a partially filled (excluding cooldown heel) container, determine any differences in temperature or specific gravity between the LNG being transferred and the LNG already in the container and, if necessary, provide a means to prevent rollover due to stratification.

(5) Verify that the transfer operations are proceeding within design conditions and that overpressure or overfilling does not occur by monitoring applicable flow rates, liquid levels, and vapor returns.

(6) Manually terminate the flow before overfilling or overpressure occurs; and

(7) Deactivate cargo transfer systems in a safe manner by depressurizing, venting, and disconnecting lines and conducting any other appropriate operations.

(c) In addition to the requirements of paragraph (b) of this section, the procedures for cargo transfer must be located at the transfer area and include provisions for personnel to:

(1) Be in constant attendance during all cargo transfer operations;

(2) Prohibit the backing of tank trucks in the transfer area, except when a person is positioned at the rear of the truck giving instructions to the driver;

(3) Before transfer, verify that—

(i) Each tank car or tank truck complies with applicable regulations governing its use;

(ii) All transfer hoses have been visually inspected for damage and defects;

(iii) Each tank truck is properly immobilized with chock wheels, and electrically grounded; and

(iv) Each tank truck engine is shut off unless it is required for transfer operations;

(4) Prevent a tank truck engine that is off during transfer operations from being restarted until the transfer lines have been disconnected and any released vapors have dissipated;

(5) Prevent loading LNG into a tank car or tank truck that is not in exclusive LNG service or that does not contain a positive pressure if it is in exclusive LNG service, until after the oxygen content in the tank is tested and if it exceeds 2 percent by volume, purged in accordance with a procedure that meets the requirements of AGA "Purging Principles and Practice;"

(6) Verify that all transfer lines have been disconnected and equipment cleared before the tank car or tank truck is moved from the transfer position; and

(7) Verify that transfers into a pipeline system will not exceed the pressure or temperature limits of the system.

§ 193.2515 Investigations of failures.

(a) Each operator shall investigate the cause of each explosion, fire, or LNG spill or leak which results in—

(1) Death or injury requiring hospitalization; or

(2) Property damage exceeding $10,000.

(b) As a result of the investigation, appropriate action must be taken to minimize recurrence of the incident.

(c) If the Director or relevant state agency under section 5 of the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1674) investigates an incident, the operator involved shall make available all relevant information and provide reasonable assistance in conducting the investigation. Unless necessary to restore or maintain service, or for safety, no component involved in the incident may be moved from its location or otherwise altered until the investigation is complete or the investigating agency otherwise provides. Where components must be moved for operational or safety reasons, they must not be removed from the plant site and must be maintained intact to the extent practicable until the investigation is complete or the investigating agency otherwise provides.

§ 193.2517 Purging.

When necessary for safety, components that could accumulate significant amounts of combustible mixtures must be purged in accordance with a procedure which meets the provisions of the AGA "Purging Principles and Practice" after being taken out of service and before being returned to service.

§ 193.2519 Communication systems.

(a) Each LNG plant must have a primary communication system that provides for verbal communications between all operating personnel at their work stations in the LNG plant.

(b) Each LNG plant in excess of 70,000 gallons storage capacity must have an emergency communication system that provides for verbal communications between all persons and locations necessary for the orderly shutdown of operating equipment and the operation of safety equipment in time of emergency. The emergency communication system must be independent of and physically separated from the primary communication system and the security communication system under § 193.2909.

(c) Each communication system required by this part must have an auxiliary source of power, except sound-powered equipment.

§ 193.2521 Operating records.

Each operator shall maintain a record of the results of each inspection, test, and investigation required by this subpart. Such records must be kept for a period of not less than 5 years.

Subpart G—Maintenance

§ 193.2601 Scope.

This subpart prescribes requirements for maintaining components at LNG plants.

§ 193.2603 General.

(a) Each component in service, including its support system, must be maintained in a condition that is compatible with its operational or safety purpose by repair, replacement, or other means.

(b) An operator may not place, return, or continue in service any component which is not maintained in accordance with this subpart.

(c) Each component taken out of service must be identified in the records kept under § 193.2639.

(d) If a safety device is taken out of service for maintenance, the component being served by the device must be taken out of service unless the same safety function is provided by an alternate means.

(e) If the inadvertent operation of a component taken out of service could cause a hazardous condition, that component must have a tag attached to the controls bearing the words "do not operate" or words of comparable meaning.

§ 193.2605 Maintenance procedures.

(a) Each operator shall determine and perform, consistent with generally accepted engineering practice, the periodic inspections or tests needed to meet the applicable requirements of this subpart and to verify that components meet the maintenance standards prescribed by this subpart.

(b) Each operator shall follow one or more manuals of written procedures for the maintenance of each component, including any required corrosion control. The procedures must include—

(1) The details of the inspections or tests determined under paragraph (a) of this section and their frequency of performance; and

(2) A description of other actions necessary to maintain the LNG plant in accordance with the requirements of this subpart and § 193.2805.

§ 193.2607 Foreign material.

(a) The presence of foreign material, contaminants, or ice shall be avoided or controlled to maintain the operational safety of each component.

(b) LNG plant grounds must be free from rubbish, debris, and other material which present a fire hazard. Grass areas on the LNG plant grounds must be maintained in a manner that does not present a fire hazard.

§ 193.2609 Support systems.

Each support system or foundation of each component must be inspected for any detrimental change that could impair support.

§ 193.2611 Fire protection.

(a) Maintenance activities on fire control equipment must be scheduled so that a minimum of equipment is taken out of service at any one time and is returned to service in a reasonable period of time.

(b) Access routes for movement of fire control equipment within each LNG plant must be maintained to reasonably provide for use in all weather conditions.

§ 193.2613 Auxiliary power sources.

Each auxiliary power source must be tested monthly to check its operational capability and tested annually for capacity. The capacity test must take into account the power needed to start up and simultaneously operate equipment that would have to be served by that power source in an emergency.

§ 193.2615 Isolating and purging.

(a) Before personnel begin maintenance activities on components handling flammable fluids which are isolated for maintenance, the component must be purged in accordance with a procedure which meets the requirements of AGA "Purging Principles and Practices," unless the maintenance procedures under § 193.2605 provide that the activity can be safely performed without purging.

(b) If the component or maintenance activity provides an ignition source, a technique in addition to isolation valves (such as removing spool pieces or valves and blank flanging the piping, or double block and bleed valving) must be used to ensure that the work area is free of flammable fluids.

§ 193.2617 Repairs.

(a) Repair work on components must be performed and tested in a manner which—

(1) As far as practicable, complies with the applicable requirements of Subpart D of this part; and

(2) Assures the integrity and operational safety of the component being repaired.

(b) For repairs made while a component is operating, each operator shall include in the maintenance procedures under § 193.2605 appropriate precautions to maintain the safety of personnel and property during repair activities.

§ 193.2619 Control systems.

(a) Each control system must be properly adjusted to operate within design limits.

(b) If a control system is out of service for 30 days or more, it must be inspected and tested for operational capability before returning it to service.

(c) Control systems in service, but not normally in operation (such as relief valves and automatic shutdown devices), must be inspected and tested once each calendar year, but with intervals not exceeding 15 months, with the following exceptions:

(1) Control systems used seasonally, such as for liquefaction or vaporization, must be inspected and tested before use each season.

(2) Control systems that are intended for fire protection must be inspected and tested at regular intervals not to exceed 6 months.

(d) Control systems that are normally in operation, such as required by a base load system, must be inspected and tested once each calendar year but with intervals not exceeding 15 months.

(e) Relief valves must be inspected and tested for verification of the valve seat lifting pressure and reseating.

§ 193.2621 Testing transfer hoses.

Hoses used in LNG or flammable refrigerant transfer systems must be—

(a) Tested once each calendar year, but with intervals not exceeding 15 months, to the maximum pump pressure or relief valve setting; and

(b) Visually inspected for damage or defects before each use.

§ 193.2623 Inspecting LNG storage tanks.

Each LNG storage tank must be inspected or tested to verify that each of the following conditions does not impair the structural integrity or safety or the tank:

(a) Foundation and tank movement during normal operation and after a major meteorological or geophysical disturbance.

(b) Inner tank leakage.

(c) Effectiveness of insulation.

(d) Frost heave.

§ 193.2625 Corrosion protection.

(a) Each operator shall determine which metallic components could, unless corrosion is controlled, have their integrity or reliability adversely affected by external, internal, or atmospheric corrosion during their intended service life.

(b) Components whose integrity or reliability could be adversely affected by corrosion must be either—

(1) Protected from corrosion in accordance with §§ 193.2627 thru 193.2635, as applicable; or

(2) Inspected and replaced under a program of scheduled maintenance in accordance with procedures established under § 193.2605.

§ 193.2627 Atmospheric corrosion control.

Each exposed component that is subject to atmospheric corrosive attack must be protected from atmospheric corrosion by—

(a) Material that has been designed and selected to resist the corrosive atmosphere involved; or

(b) Suitable coating or jacketing.

§ 193.2629 External corrosion control; buried or submerged components.

(a) Each buried or submerged component that is subject to external corrosive attack must be protected from external corrosion by—

(1) Material that has been designed and selected to resist the corrosive environment involved; or

(2) The following means:

(i) An external protective coating designed and installed to prevent corrosion attack and to meet the requirements of § 192.461 of this chapter; and

(ii) A cathodic protection system designed to protect components in their entirety in accordance with the requirements of § 192.463 of this chapter and placed in operation before October 23, 1981, or within 1 year after the component is constructed or installed, whichever is earlier.

(b) Where cathodic protection is applied, components that are electrically interconnected must be protected as a unit.

§ 193.2631 Internal corrosion control.

Each component that is subject to internal corrosive attack must be protected from internal corrosion by—

(a) Material that has been designed and selected to resist the corrosive fluid involved; or

(b) Suitable coating, inhibitor, or other means.

§ 193.2633 Interference currents.

(a) Each component that is subject to electrical current interference must be protected by a continuing program to minimize the detrimental effects of currents.

(b) Each cathodic protection system must be designed and installed so as to minimize any adverse effects it might cause to adjacent metal components.

(c) Each impressed current power source must be installed and maintained to prevent adverse interference with communications and control systems.

§ 193.2635 Monitoring corrosion control.

Corrosion protection provided as required by this subpart must be periodically monitored to give early recognition of ineffective corrosion protection, including the following, as applicable:

(a) Each buried or submerged component under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463 of this Chapter.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected at least 6 times each calendar year, but with intervals not exceeding 2½ months, to ensure that it is operating properly.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize component protection must be electrically checked for proper performance at least 6 times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each component that is protected from atmospheric corrosion must be inspected at intervals not exceeding 3 years.

(e) If a component is protected from internal corrosion, monitoring devices designed to detect internal corrosion, such as coupons or probes, must be located where corrosion is most likely to occur. However, monitoring is not required for corrosion resistant materials if the operator can demonstrate that the component will not be adversely affected by internal corrosion during its service life. Internal corrosion control monitoring devices must be checked at least two times each calendar year, but with intervals not exceeding 7½ months.

§ 193.2637 Remedial measures.

Prompt corrective or remedial action must be taken whenever an operator learns by inspection or otherwise that atmospheric, external, or internal corrosion is not controlled as required by this subpart.

§ 193.2639 Maintenance records.

(a) Each operator shall keep a record at each LNG plant of the date and type of each maintenance activity performed on each component to meet the requirements of this subpart, including periodic tests and inspections, for a period of not less than five years.

(b) Each operator shall maintain records or maps to show the location of cathodically protected components, neighboring structures bonded to the cathodic protection system, and corrosion protection equipment.

(c) Each of the following records must be retained for as long as the LNG facility remains in service:

(1) Each record or map required by paragraph (b) of this section.

(2) Records of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures.

Subpart I—Fire Protection

§ 193.2801 Scope.

This subpart prescribes requirements for fire prevention and fire control at LNG plants other than waterfront LNG plants.

§ 193.2803 General.

Each operator shall use sound fire protection engineering principles to minimize the occurrence and consequences of fire.

§ 193.2805 Fire prevention plan.

(a) Each operator shall determine—

(1) Those potential sources of ignition located inside and adjacent to the LNG plant which could cause fires that affect the safety of the plant; and

(2) Those areas, as described in Section 500-4 of NFPA-70, where the potential exists for the presence of flammable fluids in an LNG plant. Determinations made under this paragraph must be kept current.

(b) With respect to areas determined under paragraph (a)(2) of this section, each operator shall include in the operating and maintenance procedures under § 193.2503 and § 193.2605, as appropriate, steps necessary to minimize—

(1) The leakage or release of flammable fluids; and

(2) The possibility of flammable fluids being ignited by sources identified under paragraph (a)(1) of this section.

§ 193.2807 Smoking.

(a)(1) Smoking is prohibited at an LNG plant in areas identified under § 193.2805(a)(2).

(2) Smoking is permitted only in such locations that the operator designates as a smoking area.

(b) Signs marked with the words "smoking permitted" must be dispayed in prominent places in each smoking nts whose integrity or ld be adversely affected n must be either— ected from corrosion in nce with §§ 193.2627 thru 35, as applicable; or Inspected and replaced under a gram of scheduled maintenance in ccordance with procedures established under § 193.2605.

§ 193.2627 Atmospheric corrosion control.

Each exposed component that is subject to atmospheric corrosive attack must be protected from atmospheric corrosion by—

(a) Material that has been designed and selected to resist the corrosive atmosphere involved; or

(b) Suitable coating or jacketing.

§ 193.2629 External corrosion control; buried or submerged components.

(a) Each buried or submerged component that is subject to external corrosive attack must be protected from external corrosion by—

(1) Material that has been designed and selected to resist the corrosive environment involved; or

(2) The following means:

(i) An external protective coating designed and installed to prevent corrosion attack and to meet the requirements of § 192.461 of this chapter; and

(ii) A cathodic protection system designed to protect components in their entirety in accordance with the requirements of § 192.463 of this chapter and placed in operation before October 23, 1981, or within 1 year after the component is constructed or installed, whichever is earlier.

(b) Where cathodic protection is applied, components that are electrically interconnected must be protected as a unit.

§ 193.2631 Internal corrosion control.

Each component that is subject to internal corrosive attack must be protected from internal corrosion by—

(a) Material that has been designed and selected to resist the corrosive fluid involved; or

(b) Suitable coating, inhibitor, or other means.

§ 193.2633 Interference currents.

(a) Each component that is subject to electrical current interference must be protected by a continuing program to minimize the detrimental effects of currents.

(b) Each cathodic protection system must be designed and installed so as to minimize any adverse effects it might cause to adjacent metal components.

(c) Each impressed current power source must be installed and maintained to prevent adverse interference with communications and control systems.

§ 193.2635 Monitoring corrosion control.

Corrosion protection provided as required by this subpart must be periodically monitored to give early recognition of ineffective corrosion protection, including the following, as applicable:

(a) Each buried or submerged component under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463 of this Chapter.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected at least 6 times each calendar year, but with intervals not exceeding 2½ months, to ensure that it is operating properly.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize component protection must be electrically checked for proper performance at least 6 times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each component that is protected from atmospheric corrosion must be inspected at intervals not exceeding 3 years.

(e) If a component is protected from internal corrosion, monitoring devices designed to detect internal corrosion, such as coupons or probes, must be located where corrosion is most likely to occur. However, monitoring is not required for corrosion resistant materials if the operator can demonstrate that the component will not be adversely affected by internal corrosion during its service life. Internal corrosion control monitoring devices must be checked at least two times each calendar year, but with intervals not exceeding 7½ months.

§ 193.2637 Remedial measures.

Prompt corrective or remedial action must be taken whenever an operator learns by inspection or otherwise that atmospheric, external, or internal corrosion is not controlled as required by this subpart.

§ 193.2639 Maintenance records.

(a) Each operator shall keep a record at each LNG plant of the date and type of each maintenance activity performed on each component to meet the requirements of this subpart, including periodic tests and inspections, for a period of not less than five years.

(b) Each operator shall maintain records or maps to show the location of cathodically protected components, neighboring structures bonded to the cathodic protection system, and corrosion protection equipment.

(c) Each of the following records must be retained for as long as the LNG facility remains in service:

(1) Each record or map required by paragraph (b) of this section.

(2) Records of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures.

Subpart I—Fire Protection

§ 193.2801 Scope.

This subpart prescribes requirements for fire prevention and fire control at LNG plants other than waterfront LNG plants.

§ 193.2803 General.

Each operator shall use sound fire protection engineering principles to minimize the occurrence and consequences of fire.

§ 193.2805 Fire prevention plan.

(a) Each operator shall determine—

(1) Those potential sources of ignition located inside and adjacent to the LNG plant which could cause fires that affect the safety of the plant; and

(2) Those areas, as described in Section 500-4 of MFPA-70, where the potential exists for the presence of flammable fluids in an LNG plant. Determinations made under this paragraph must be kept current.

(b) With respect to areas determined under paragraph (a)(2) of this section, each operator shall include in the operating and maintenance procedures under § 193.2503 and § 193.2605, as appropriate, steps necessary to minimize—

(1) The leakage or release of flammable fluids; and

(2) The possibility of flammable fluids being ignited by sources identified under paragraph (a)(1) of this section.

§ 193.2807 Smoking.

(a)(1) Smoking is prohibited at an LNG plant in areas identified under § 193.2805(a)(2).

(2) Smoking is permitted only in such locations that the operator designates as a smoking area.

(b) Signs marked with the words "smoking permitted" must be dispayed in prominent places in each smoking area designated under paragraph (a) of this section.

(c) Signs marked with the words "NO SMOKING" must be displayed in prominent places in areas where smoking is prohibited.

§ 193.2809 Open fires.

(a) No open fires are permitted at an LNG plant, except at flare stacks and at times and places designated by the operator.

(b) Whenever an open fire is designated, there must be at the site of the fire—

(1) Trained fire fighting personnel; and

(2) Fire control equipment which has the capability of extinguishing the fire.

(c) The fire fighting personnel and equipment must remain at the fire site until the fire is extinguishd and there is no possibility of reignition.

§ 193.2811 Hotwork.

Welding, flame cutting, and similar operations are prohibited, except at times and places that the operator designates in writing as safe and when constantly supervised in accordance with NFPA-51B.

§ 193.2813 Storage of flammable fluids.

Flammable fluids may not be stored in areas where ignition sources are present, unless stored in accordance with the requirements of Chapter 4 of NFPA 30.

§ 193.2815 Motorized equipment.

Use of motor vehicles and other motorized equipment which constitute potential ignition sources is prohibited in an impounding space, in areas within 15 m (49.2 ft) of a storage tank, and in areas within 15 m (49.2 ft) of processing equipment containing a flammable fluid except—

(a) At times the operator designates in writing as safe; and

(b) When the motorized equipment is constantly attended.

§ 193.2817 Fire equipment.

(a) Each operator shall determine: (1) the types and sizes of fires that may reasonably be expected to occur within and adjacent to each LNG plant that could affect the safety of components; and (2) The foreseeable consequences of these fires, including the failure of components or buildings due to heat exposure.

(b) Each operator shall provide and maintain fire control equipment and supplies in accordance with the applicable requirements of NFPA 59A to protect or cool components that could fail due to heat exposure from fires determined under paragraph (a) of this section and either worsen an emergency or endanger persons or property located outside the plant. Protection or cooling must be provided for as long as the heat exposure exists. The fire control equipment and supplies must include the following:

(1) Portable fire extinguishers suitable for types of fires identified under paragraph (a) of this section; and

(2) If the total inventory of LNG is 265 m^3 (70,000 gal.) or more, a water supply and associated delivery system.

(c) Each operator shall determine the type, size, quantity and location of the fire control equipment and supplies required under paragraph (b) of this section.

(d) Each operator shall provide each facility person who may be endangered by exposure to fire or the products of combustion in performing fire control duties protective clothing and equipment, including, if necessary, a self-contained breathing apparatus.

(e) Portable fire control equipment, protective clothing and equipment for personnel use, controls for fixed fire control equipment, and fire control supplies must be conspicuously located, marked for easy recognition, and readily available for use.

(f) Fire control equipment must have operating instructions. Instructions must be attached to portable equipment and placed at the location of controls for fixed equipment.

§ 193.2819 Gas detection.

(a) All areas determined under § 193.2805(a)(2) in which a hazard to persons or property could exist must be continuously monitored for the presence of flammable gases and vapors with fixed flammable gas detection systems provided and maintained according to the applicable requirements of NFPA 59A.

(b) Each fixed flammable gas detection system must be provided with audible and visible alarms located at an attended control room or control station, and an audible alarm in the area of gas detection.

(c) Flammable gas detection alarms must be set to activate at not more than 25 percent of the lower flammable limit of the gas or vapor being monitored.

(d) Gas detection systems must be installed so that they can be readily tested as required by NFPA 59A.

(e) A minimum of two portable flammable gas detectors capable of measuring the lower flammable limit must be available at the LNG plant for use at all times.

(f) All enclosed buildings located on an LNG plant must be continuously monitored for the presence of flammable gases and vapors with a fixed flammable gas detection system that provides a visible or audible alarm outside the enclosed building. The systems must be provided and maintained according to the applicable requirements of NFPA 59A.

§ 193.2821 Fire detection.

(a) Fire detectors that continuously monitor for the presence of either flame, heat, or products of combustion must be provided in all areas determined under § 193.2805(a)(2) in which a hazard to persons or property could exist and in all other areas that are used for the storage of flammable or combustible material.

(b) Each fire detection system must be provided with audible and visible alarms located at an attended control room or control station, and an audible alarm in the area of fire detection. The systems must be provided and maintained according to the applicable requirements of NFPA 59A.

Subpart J—Security

§ 193.2901 Scope.

This subpart prescribes requirements for security at LNG plants other than waterfront LNG plants.

§ 193.2903 Security procedures.

Each operator shall prepare and follow one or more manuals of written procedures to provide security for each LNG plant. The procedures must be available at the plant in accordance with § 193.2017 and include at least:

(a) A description and schedule of security inspections and patrols performed in accordance with § 193.2913;

(b) A list of security personnel positions or responsibilities utilized at the LNG plant;

(c) A brief description of the duties associated with each security personnel position or responsibility;

(d) Instructions for actions to be taken, including notification of other appropriate plant personnel and law enforcement officials, when there is any indication of an actual or attempted breach of security;

(e) Methods for determining which persons are allowed access to the LNG plant;

(f) Positive identification of all persons entering the plant and on the plant, including methods at least as effective as picture badges; and

(g) Liaison with local law enforcement officials to keep them informed about current security procedures under this section.

§ 193.2905 Protective enclosures.

(a) The following facilities must be surrounded by a protective enclosure:

(1) Storage tanks;

(2) Impounding systems;

(3) Vapor barriers;

(4) Cargo transfer systems;

(5) Process, liquefaction, and vaporization equipment;

(6) Control rooms and stations;

(7) Control systems;

(8) Fire control equipment;

(9) Security communications systems; and

(10) Alternative power sources.

The protective enclosure may be one or more separate enclosures surrounding a single facility or multiple facilities.

(b) Ground elevations outside a protective enclosure must be graded in a manner that does not impair the effectiveness of the enclosure.

(c) Protective enclosures may not be located near features outside of the facility, such as trees, poles, or buildings, which could be used to breach the security.

(d) At least two accesses must be provided in each protective enclosure and be located to minimize the escape distance in the event of emergency.

(e) Each access must be locked unless it is continuously guarded. During normal operations, an access may be unlocked only by persons designated in writing by the operator. During an emergency, a means must be readily available to all facility personnel within the protective enclosure to open each access.

§ 193.2907 Protective enclosure construction.

(a) Each protective enclosure must have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed.

(b) Protective enclosures must be fences or walls constructed as follows:

(1) Fences must be chainlink security fences constructed of No. 11 American wire gauge or heavier metal wire.

(2) Walls must be vertical and constructed of stone, brick, cinder block, concrete, steel or comparable materials.

(3) Protective enclosures must be topped by three or more strands of barbed wire or similar materials on brackets angled outward between 30° and 45° from the vertical, with a height of at least 2.4m (8 ft.) including approximately one foot of barbed topping.

(4) Openings in or under protective enclosures must be secured by grates, doors or covers of construction and fastening of sufficient strength such that the integrity of the protective enclosure is not reduced by any opening.

(c) Paragraphs (b)(1) thru (b)(3) of the section do not apply to protective enclosures constructed before October 23, 1980.

(1) Are made of noncombustible materials;

(2) Are at least 2.1m (7 ft.) in height including approximately one foot of barbed or similar topping; and

(3) Have served to protect the LNG plant without having been breached during their history of service.

§ 193.2909 Security communications.

A means must be provided for:

(a) Prompt communications between personnel having supervisory security duties and law enforcement officials; and

(b) Direct communications between all on-duty personnel having security duties and all control rooms and control stations.

§ 193.2911 Security lighting.

Where security warning systems are not provided for security monitoring under § 193.2913, the area around the facilities listed under § 193.2905(a) and each protective enclosure must be illuminated with a minimum in service lighting intensity of not less than 2.2 lux (0.2 ft^{c}) between sunset and sunrise.

§ 193.2913 Security monitoring.

Each protective enclosure and the area around each facility listed in § 193.2905(a) must be monitored for the presence of unauthorized persons. Monitoring must be by visual observation in accordance with the schedule in the security procedures under § 193.2903(a) or by security warning systems that continuously transmit data to an attended location. At an LNG plant with less than 40,000 m^3 (250,000 bbl) of storage capacity, only the protective enclosure must be monitored.

§ 193.2915 Alternative power sources.

An alternative source of power that meets the requirements of § 193.2445 must be provided for security lighting and security monitoring and warning systems required under §§ 193.2911 and 193.2913.

§ 193.2917 Warning signs.

(a) Warning signs must be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 30m (100 ft.) from any way that could reasonably be used to approach the enclosure.

(b) Signs must be marked with at least the following on a background of sharply contrasting color:

The words "NO TRESPASSING," or words of comparable meaning.

Subpart H—Personnel Qualifications and Training

§ 193.2701 Scope.

This subpart prescribes requirements for personnel qualifications and training.

§ 193.2703 Design and fabrication.

For the design and fabrication of components, each operator shall use—

(a) With respect to design, persons who have demonstrated competence by training or experience in the design of comparable components.

(b) With respect to fabrication, persons who have demonstrated competence by training or experience in the fabrication of comparable components.

§ 193.2705 Construction, installation, inspection, and testing.

(a) Supervisors and other personnel utilized for construction, installation, inspection, or testing must have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related experience and accomplishments.

(b) Each operator must periodically determine whether inspectors performing duties under § 193.2307 are satisfactorily performing their assigned function.

§ 193.2707 Operations and maintenance.

(a) Each operator shall utilize for operation or maintenance of components only those personnel who have demonstrated their capability to perform their assigned functions by—

(1) Successful completion of the training required by §§ 193.2713 and 193.2717; and

(2) Experience related to the assigned operation or maintenance function; and

(3) Acceptable performance on a proficiency test relevant to the assigned function.

(b) A person who does not meet the requirements of paragraph (a) of this section may operate or maintain a component when accompanied and directed by an individual who meets the requirements.

(c) Corrosion control procedures under § 193.2605(b), 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 corrosion control technology.

§ 193.2709 Security.

Personnel having security duties must be qualified to perform their assigned duties by successful completion of the training required under § 193.2715.

§ 193.2711 Personnel health.

Each operator shall follow a written plan to verify that personnel assigned operating, maintenance, security, or fire protection duties at the LNG plant do not have any physical condition that would impair performance of their assigned duties. The plan must be designed to detect both readily observable disorders, such as physical handicaps or injury, and conditions requiring professional examination for discovery.

§ 193.2713 Training; operations and maintenance.

(a) Each operator shall provide and implement a written plan of initial training to instruct—

(1) All permanent maintenance, operating, and supervisory personnel—

(i) About the characteristics and hazards of LNG and other flammable fluids used or handled at the facility, including, with regard to LNG, low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray;

(ii) About the potential hazards involvd in operating and maintenance activities; and

(iii) To carry out aspects of the operating and maintenance procedures under §§ 193.2503 and 193.2605 that relate to their assigned functions; and

(2) All personnel—

(i) To carry out the emergency procedures under § 193.2509 that relate to their assigned functions; and

(ii) To give first-aid; and

(3) All operating and appropriate supervisory personnel—

(i) To understand detailed instructions on the facility operations, including controls, functions, and operating procedures; and

(ii) To understand the LNG transfer procedures provided under § 193.2513.

(b) A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel current on the knowledge and skills they gained in the program of initial instruction.

§ 193.2715 Training; security.

(a) Personnel responsible for security at an LNG plant must be trained in accordance with a written plan of initial instruction to:

(1) Recognize breaches of security;

(2) Carry out the security procedures under § 193.2903 that relate to their assigned duties;

(3) Be familiar with basic plant operations and emergency procedures, as necessary to effectively perform thei assigned duties; and

(4) Recognize conditions where security assistance is needed.

(b) A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel having security duties current on the knowledge and skills they gained in the program of initial instruction.

§ 193.2717 Training; fire protection.

(a) All personnel involved in maintenance and operations of an LNC plant, including their immediate supervisors, must be trained in accordance with a written plan of initi instruction, including plant fire drills, t

(1) Know and follow the fire prevention procedures under § 193.2805(b);

(2) Know the potential causes and areas of fire determined under § 193.2805(a);

(3) Know the types, sizes, and predictable consequences of fire determined under § 193.2817(a); and

(4) Know and be able to perform their assigned fire control duties according to the procedures established under § 193.2509 and by proper use of equipment provided under § 193.2817.

(b) A written plan of continuing instruction, including plant fire drills, must be conducted at intervals of not more than two years to keep personnel current on the knowledge and skills they gained in the instruction under paragraph (a) of the section.

§ 193.2719 Training; records.

(a) Each operator shall maintain a system of records which—

(1) Provide evidence that the training programs required by this subpart have been implemented; and

(2) Provide evidence that personnel have undergone and satisfactorily completed the required training programs.

(b) Records must be maintained for one year after personnel are no longer assigned duties at the LNG plant.

Appendix A to Part 193—Incorporation by Reference

I. List of Organizations and Addresses

A. American Concrete Institute (ACI), P.O. Box 19150, Redford Station, Detroit, Michigan 48219.

B. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, Virginia 22209.

C. American National Standards Institute (ANSI), 1430 Broadway, New York, New York 10018.

D. American Petroleum Institute (API), 2101 L Street, NW., Washington, D.C. 20037.

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

F. National Fire Protection Association (NFPA), 470 Atlantic Avenue, Boston, Massachusetts 02210.

G. International Conference of Building Officials, 5360 South Workman Hill Road, Whittier, California 90601.

II. Documents Incorporated by Reference

A. American Concrete Institute (ACI)

1. ACI Standard 311–75—Recommended Practice for Concrete Inspection, (1975 edition).

B. American Gas Association (AGA)

1. Evaluation of LNG Vapor Control Methods. (October 1974 edition).

2. Purging Principles and Practice (1975 edition).

C. American National Standards Institute (ANSI)

1. ANSI A 58.1 Building Code Requirements for Minimum Design Loads in Buildings and Other Structures.

D. American Petroleum Institute (API)

1. API 620-Recommended Rules for Design and Construction of Large, Welded, Low Pressure Storage Tanks (6th edition, Dec. 1978)

2. API 1104 Standard for Welding Pipelines and Related Facilities (15 edition, 1980)

3. API 6D Specifications for Pipeline Valves (17 edition, 1977).

E. American Society of Mechanical Engineers (ASME)

1. ANSI B31.3 Chemical and Plant Petroleum Refinery Piping (1976 edition).

2. ASME Boiler and Pressure Vessel Code, Section 1 Power Boilers (1977 edition).

3. ASME Boiler and Pressure Vessel Code, Section 8 Division 1 (1977 edition).

4. ASME Boiler and Pressure Vessel Code, Section 8 Division 2, Alternative Rules (1977 edition).

5. ASME Boiler and Pressure Vessel Code, Section 9 Welding and Brazing Qualifications (1977 edition).

6. ASME Boiler and Pressure Vessel Code, Section 4 Heating Boilers.

7. ANSI B31.5 Refrigeration Piping (1974 edition).

8. ANSI B31.8 Gas Transmission and Distribution Piping Systems (1975 edition).

F. International Conference of Building Officials

1. UBC, Uniform Building Code (1979 edition).

G. National Fire Protection Association (NFPA)

1. NFPA No. 37 Stationary Combustion Engine and Gas Turbines (1979 edition).

2. NFPA No. 59A, Storage and Handling of LNG (1972 edition for § 193.2005(c), otherwise 1979 edition).

3. NFPA No. 70 National Electric Code (1978 edition).

4. NFPA No. 30, Flammable Liquids (1981 edition).

5. NFPA No. 51 B, Cutting and Welding Processes (1977 edition).

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