Chapter Trans 29

APPENDIX 1

FEDERAL REGULATIONS AND PROCEDURES ADOPTED BY THE WISCONSIN DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration, DOT

49 CFR §193.2001 Subpart A – General

49 CFR §193.2051 Subpart B – Siting Requirements

49 CFR §193.2301 Subpart D – Construction

RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION, DOT

49 CFR §193.2001, Subpart A June 1998

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 pipeline safety laws (49 U.S.C. 60101 et seq.) 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)).

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

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193−1, 45 FR 57418, Aug. 28, 1980; Amdt. 193−10, 61 FR 18517, April 26, 1996]

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 ANSI/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.

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

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193−1, 45 FR 57418, Aug. 28, 1980; Amdt. 193−2, 45 FR 70404, Oct. 23, 1980; 58 FR 14522, March 18, 1993]

193.2007 Definitions.

As used in this part:

"Administrator" means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

"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.

"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 meters 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 (CH4) 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.

"m3" 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, corporation, 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.

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

"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.

"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.

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

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193–1, 45 FR 57418, Aug. 28, 1980; Amdt. 193–2, 45 FR 70404, Oct. 23, 1980; Amdt. 193–10, 61 FR 18517, April 26, 1996]

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 Research and Special Programs Administration, 400 Seventh Street, SW., Washington, DC, and at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, the incorporated materials are available from the respective organizations listed in appendix A to this part.

(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)

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193–2, 45 FR 70410, Oct. 23, 1980; 50 FR 45732, Nov. 1, 1985; 58 FR 14522, March 18, 1993]

193.2015 [Reserved]

[59 FR 17281, April 12, 1994]

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 Administrator or any State Agency that has submitted a current certification or agreement with respect to the plant under the pipeline safety laws (49 U.S.C. 60101 et seq.). 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 Administrator or the State Agency that has submitted a current certification under section 5(a) of the Natural Gas Pipeline Safety Act with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

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

[Amdt. 193–2, 45 FR 70404, Oct. 23, 1980; Amdt. 193–7, 56 FR 31090, July 9, 1991; Amdt. 193–10, 61 FR 18517, April 26, 1996]

193.2019 Mobile and temporary LNG facilities

(a) Mobile and temporary LNG facilities for peakshaving application, for service maintenance during gas pipeline systems repair/alteration, or for other short term applications need not meet the requirements of this part if the facilities are in compliance with applicable sections of NFPA 59A (1996 edition).

(b) The State agency having jurisdiction over pipeline safety in the State in which the portable LNG equipment is to be located must be provided with a location description for the installation at least 2 weeks in advance, including to the extent practical, the details of siting, leakage containment or control, fire fighting equipment, and methods employed to restrict public access, except that in the case of emergency where such notice is not possible, as much advance notice as possible must be provided.

[Amdt. 193–14, 62 FR 41312, Aug. 1, 1997; 62 FR 48952, Sept. 18, 1997]

RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION, DOT

49 CFR §193.2051, Subpart B June 1998

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.

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

[Amdt. 193–1, 45 FR 57418, Aug. 28, 1980]

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 the horizontal distance measured from the impoundment area to the target where the following apply:

(1) The maximum calculated exclusion distance for each thermal flux level shall be used for that exposure (offsite target) in paragraph (d) of this section.

(2) The wind speed producing the maximum exclusion distances shall be used except for wind speeds that occur less than 5 percent of the time based on recorded data for the area.

(3) The ambient temperature and relative humidity that produce the maximum exclusion distance shall be used except that

values that occur less than 5 percent of the time based on recorded data for the area shall not be used.

(4) Properties of LNG with the highest anticipated heating value shall be used.

(5) The height of the flame base should be that of any dike or containment in relation to the horizontal reference plane. The height of the target shall be in relation to the same reference plane.

(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) The method of calculating the exclusion distances for levels of radiant exposure listed in paragraph (d) of this section shall be the method described in Gas Research Institute report GRI–89/0176 and also available as the "LNGFIRE" computer program from GRI.

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 Administrator for approval, with supportive data as necessary to demonstrate validity; and

(iv) Have received approval by the Administrator.

(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 area 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 paragraphs (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 line of the facility	(0.8)	10,000

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

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193–1, 45 FR 57418, Aug. 28, 1980; Amdt. 193–13, 62 FR 8404, Feb. 25, 1997; 62 FR 36465, July 8, 1997]

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 in an impounding system. Dispersion distances must be determined in accordance with the following dispersion parameters, using the "DEGADIS" model described in Gas Research Institute report No. GRI 89/0242 titled "LNG Vapor Dispersion Predication with the DEGADIS Dense Gas Dispersion Model", or a model for vapor dispersion which meets the requirements of §193.2057(c)(2)(ii) through (iv):

(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 temperatures = 0.0 C.

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

(4) A surface roughness factor of 3 cm shall be used. Higher values for the roughness factor may be used if it can be shown that the terrain both upwind and downwind of the vapor cloud has dense vegetation and that the vapor cloud height is more than ten times the height of the obstacles encountered by the vapor cloud.

(d) Vaporization 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 the 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 1974 AGA report titled "Evaluation of LNG Vapor Control Methods," or by using an equivalent personal computer program based on equation C–9 or by an alternative model which meets the requirements of §193.2057(c)(2)(ii) through (iv).

(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 Administrator, RSPA 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.

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

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193–1, 45 FR 57418, Aug. 28, 1980; Amdt. 193–13, 62 FR 8404, Feb. 25, 1997; 62 FR 36465, July 8, 1997; Amdt. 193–15, 63 FR 7723, Feb. 17, 1998]

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 Administrator grants an approval for the site:

(1) The estimated design horizontal acceleration exceeds 0.8g 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.

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

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193–1, 45 FR 57419, Aug. 28, 1980]

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 ASCE 7–88.

(2) For all other LNG facilities ––

(i) An assumed sustained wind velocity of not less than 200 miles per hour, unless the Administrator, RSPA 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.

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

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193–1, 45 FR 57419, Aug. 28, 1980; 58 FR 14522, March 18, 1993]

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 ANSI/NFPA 59A.

[58 FR 14522, March 18, 1993]

RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION, DOT

49 CFR §193.2301, Subpart D June 1998

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.

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

[Amdt. 193–2, 45 FR 70404, Oct. 23, 1980]

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 311.4R–88 or ACI 311.5R–88.

(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.

[58 FR 14522, March 18, 1993]

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 –29 degrees C (–20 degrees 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.

[45 FR 9203, 11, 1980, as amended at 47 FR 32720, July 29, 1982; 47 FR 33965, Aug. 5, 1982]

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 ASME/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.

[58 FR 14522, March 18, 1993]

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 345 of ASME/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.

[58 FR 14522, March 18, 1993]

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 welds 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 ASME/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 Q.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.

[58 FR 14522, March 18, 1993; Amdt. 193–10, 61 FR 18517, April 26, 1996]

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, Q9, and Q10 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.

[58 FR 14522, March 18, 1993]

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.