NFPA® 59A

Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)

2016

NFPA®

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NFPA® 59A

Standard for the

Production, Storage, and Handling of Liquefied Natural Gas (LNG)

2016 Edition

This edition of NFPA 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*, was prepared by the Technical Committee on Liquefied Natural Gas. It was issued by the Standards Council on November 14, 2015, with an effective date of December 4, 2015, and supersedes all previous editions.

This document has been amended by one or more Tentative Interim Amendments (TIAs) and/or Errata. See "Codes & Standards" at www.nfpa.org for more information.

This edition of NFPA 59A was approved as an American National Standard on December 4, 2015.

Origin and Development of NFPA 59A

A committee of the American Gas Association began work on a standard for liquefied natural gas circa 1960. In the autumn of 1964, a draft was submitted to NFPA with the request that it be considered as the basis for an NFPA standard. The Sectional Committee on Utility Gas prepared a standard that was adopted tentatively at the 1966 NFPA Annual Meeting at the recommendation of the Committee on Gases.

With the formation of the Committee on Fuel Gases in the summer of 1966, the standard was assigned to that committee and its subcommittee on Utility Gas Plants. The first official edition was adopted at the 1967 NFPA Annual Meeting under the sponsorship of the Committee on Fuel Gases.

By early 1969, it was apparent that the use of LNG was expanding considerably beyond the utility gas plant applications covered by the 1967 edition. The American Petroleum Institute suggested that one of its standards, PUBL 2510A, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*, be used to help develop a standard having a broader scope. The Committee on Liquefied Natural Gas was established for that purpose. The 1971 edition was the first edition of NFPA 59A developed under the broadened scope. Subsequent editions were adopted in 1972, 1975, 1979, 1985, 1990, 1994, 1996, and 2001.

The 2006 edition included revisions in compliance with the *Manual of Style for NFPA Technical Committee Documents*. Chapter 5 was revised to cover double and full containment LNG storage containers. Definitions of these types of containers were also added to the standard. Seismic design criteria for LNG containers were revised to correlate with the requirements of ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. Chapter 11 was revised to add requirements for a contingency plan for potential LNG marine transfer incidents.

In the 2009 edition, additional vapor dispersion models were allowed where they are evaluated and approved by an independent body using the new Model Evaluation Protocol developed by the NFPA Research Foundation. The Design Spill table was revised to separate the design spill requirements for over-the-top fill/withdrawal containers, other containers, and process areas. Scope statements were added to each chapter, and the term *radiant heat flux* replaced *thermal radiation* throughout the document.

In the 2013 edition, Annex E, Performance-Based Alternative Standard for Plant Siting, was revised and relocated to the mandatory text as new Chapter 15, Performance (Risk Assessment) Based LNG Plant Siting. Use of the performance-based option required approval of the authority having jurisdiction. The performance-based option required analyzing the risks to persons and property in the area surrounding the proposed LNG plant based on risk mitigation techniques incorporated into the facility design. All of the minimum requirements of earlier chapters of NFPA 59A also had to be met. Chapter 15 provided several tables and figures to assist a facility designer in identifying those risks and determining if the risks are tolerable, as defined in Chapter 15.

The 2013 edition also incorporated several revisions to promote consistency between NFPA 59A and the Code of Federal Regulations, as well as some new terminology for tank systems. In addition, Chapters 7 and 14 were reorganized for easier use.

In the 2016 edition, several definitions have been revised to establish a hierarchy of components, facilities, and plants. A new definition for *LNG facility* has been added, and the definitions for *LNG plant* and *component* have been revised to maintain consistency. Subsequent chapters have been revised to correspond to the new definitions.

Additional changes have been made to improve the fire safe design of outer concrete containers to avoid explosive spalling during a fire event. Revisions have been made to requirements for inspections after repairs, detection of leaks, and post seismic events to provide greater confidence in the system's continued safety and integrity.

The 2016 edition also incorporates several revisions to enhance the use of Annex A. NFPA documents that were listed in Annex A as informational references in prior editions have been moved into Chapter 12 as enforceable code in order to address the design and installation requirements for fire protection systems. New and revised annex material has been added for numerous sections to provide additional information, guidance, and clarification, as well as to point users to reference materials for further guidance.

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NOTE: Membership on a committee shall not in and of itself constitute an endorsement of the Association or any document developed by the committee on which the member serves.

Committee Scope: This Committee shall have primary responsibility for documents on safety and related aspects in the liquefaction of natural gas and the transport, storage, vaporization, transfer, and use of liquefied natural gas.

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NFPA 59A

Standard for the

Production, Storage, and Handling of Liquefied Natural Gas (LNG)

2016 Edition

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NOTICE: An asterisk (*) following the number or letter designating a paragraph indicates that explanatory material on the paragraph can be found in Annex A.

A reference in brackets [ ] following a section or paragraph indicates material that has been extracted from another NFPA document. As an aid to the user, the complete title and edition of the source documents for extracts in mandatory sections of the document are given in Chapter 2 and those for extracts in informational sections are given in Annex E. Extracted text may be edited for consistency and style and may include the revision of internal paragraph references and other references as appropriate. Requests for interpretations or revisions of extracted text shall be sent to the technical committee responsible for the source document.

Information on referenced publications can be found in Chapter 2 and Annex E.

Chapter 1 Administration

1.1* Scope.

1.1.1 This standard shall apply to the following:

(1) Facilities that liquefy natural gas
(2) Facilities that store, vaporize, transfer, and handle liquefied natural gas (LNG)
(3) The training of all personnel involved with LNG
(4) The design, location, construction, maintenance, and operation of all LNG facilities

1.1.2 This standard shall not apply to the following:

(1) Frozen ground containers
(2) Portable storage containers stored or used in buildings
(3) All LNG vehicular applications, including fueling of LNG vehicles

1.2 Purpose. The purpose of this standard is to provide minimum fire protection, safety, and related requirements for the location, design, construction, security, operation, and maintenance of LNG plants.

1.3* Equivalency. Nothing in this standard is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this standard.

1.3.1 Technical documentation shall be submitted to the authority having jurisdiction to demonstrate equivalency.

1.3.2 The system, method, or device shall be approved for the intended purpose by the authority having jurisdiction.

1.4 Retroactivity. The provisions of this standard reflect a consensus of what is necessary to provide an acceptable degree of protection from the hazards addressed in this standard at the time the standard was issued.

1.4.1 Unless otherwise specified, the provisions of this standard shall not apply to facilities, equipment, structures, or installations that existed or were approved for construction or installation prior to the effective date of the standard. Where specified, the provisions of this standard shall be retroactive.

1.4.2 In those cases where the authority having jurisdiction determines that the existing situation presents an unacceptable degree of risk, the authority having jurisdiction shall be permitted to apply retroactively any portions of this standard deemed appropriate.

1.4.3 The retroactive requirements of this standard shall be permitted to be modified if their application clearly would be impractical in the judgment of the authority having jurisdiction, and only where it is clearly evident that a reasonable degree of safety is provided.

1.5* SI Units. SI units in this standard shall be based on IEEE/ASTM SI 10, *American National Standard for Use of the International System of Units (SI): The Modern Metric System.*

1.5.1 Alternate usage of U.S. customary units and SI units on a single project shall not be used to lessen clearance distances.

1.6 Pressure Measurement. All pressures expressed in this document are gauge pressures unless specifically noted otherwise.

1.7 Referenced Standards. Reference is made to both U.S. and Canadian standards, because this standard is prepared for use in both the United States and Canada, as well as in other countries.

1.7.1 Where this standard is adopted, the adoption shall include a statement of which U.S. or Canadian reference standards shall be used.

1.7.2 If no such statement is made, the user shall use either all available U.S. or all available Canadian reference standards.

1.7.3 If other reference standards are to be used, it shall be so stated.

Chapter 2 Referenced Publications

2.1 General. The documents or portions thereof listed in this chapter are referenced within this standard and shall be considered part of the requirements of this document.

2.2 NFPA Publications. National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02169-7471.

NFPA 10, *Standard for Portable Fire Extinguishers,* 2013 edition.

NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam,* 2016 edition.

NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems,* 2015 edition.

NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems,* 2015 edition.

NFPA 13, *Standard for the Installation of Sprinkler Systems,* 2016 edition.

NFPA 14, *Standard for the Installation of Standpipe and Hose Systems,* 2016 edition.

NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection,* 2016 edition.

NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems,* 2015 edition.

NFPA 17, *Standard for Dry Chemical Extinguishing Systems,* 2013 edition.

NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection,* 2016 edition.

NFPA 22, *Standard for Water Tanks for Private Fire Protection,* 2013 edition.

NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances,* 2016 edition.

NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,* 2014 edition.

NFPA 30, *Flammable and Combustible Liquids Code,* 2015 edition.

NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines,* 2015 edition.

NFPA 51B, *Standard for Fire Prevention During Welding, Cutting, and Other Hot Work,* 2014 edition.

NFPA 54, *National Fuel Gas Code,* 2015 edition.

NFPA 58, *Liquefied Petroleum Gas Code,* 2014 edition.

NFPA 59, *Utility LP-Gas Plant Code,* 2015 edition.

NFPA 68, *Standard on Explosion Protection by Deflagration Venting,* 2013 edition.

NFPA 70® , *National Electrical Code®,* 2014 edition.

NFPA 72® , *National Fire Alarm and Signaling Code,* 2016 edition.

NFPA *101®* , *Life Safety Code®,* 2015 edition.

NFPA 110, *Standard for Emergency and Standby Power Systems,* 2016 edition.

NFPA 274, *Standard Test Method to Evaluate Fire Performance Characteristics of Pipe Insulation,* 2013 edition.

NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids,* 2012 edition.

NFPA 496, *Purged and Pressurized Enclosures for Electrical Equipment,* 2013 edition.

NFPA 600, *Standard on Fire Brigades,* 2015 edition.

NFPA 750, *Standard on Water Mist Fire Protection Systems,* 2015 edition.

NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems,* 2016 edition.

NFPA 1901, *Standard for Automotive Fire Apparatus,* 2016 edition.

NFPA 1961, *Standard on Fire Hose,* 2013 edition.

NFPA 1962, *Standard for the Care, Use, Inspection, Service Testing, and Replacement of Fire Hose, Couplings, Nozzles, and Fire Hose Appliances,*2013 edition.

NFPA 1963, *Standard for Fire Hose Connections,* 2014 edition.

NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems,* 2015 edition.

NFPA 5000® , *Building Construction and Safety Code®,* 2015 edition.

Fire Protection Research Foundation, *"Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities,"* 2007 edition.

2.3 Other Publications.

2.3.1 ACI Publications. American Concrete Institute, P.O. Box 9094, Farmington Hills, MI 48333.

ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*, 2000.

ACI 318, *Building Code Requirements for Structural Concrete and Commentary,* 2011.

ACI 350, *Code Requirements for Environmental Engineering Concrete Structures*, 2006.

ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases,* 2010.

2.3.2 ALPEMA Publications. Brazed Aluminum Plate-Fin Heat Exchanger Manufacturer's Association, IHS (secretariat), 321 Inverness Drive South, Englewood, CO 80112.

The Standards of the Brazed Aluminum Plate-Fin Heat Exchanger Manufacturer's Association, 3rd Edition, 2012.

2.3.3 API Publications. American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005-4070.

API 6D, *Specification for Pipeline Valves,* 2007 with errata 1-6 (2011) and addendums 1, 2 (2011), and 3 (2012).

API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* 2008, 11th edition, including 2009, 2010, and 2012 addendums.

API 625, *Tank Systems for Refrigerated Liquefied Gas Storage,* 2010, with addendum 1, July 1, 2013

API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations,* 2001.

2.3.4 ASCE Publications. American Society of Civil Engineers, 1801 Alexander Bell Drive, Reston, VA 20191-4400.

ASCE 7, *Minimum Design Loads for Buildings and Other Structures,* 2010.

2.3.5 ASME Publications. American Society of Mechanical Engineers, Two Park Avenue, New York, NY 10016-5990.

Boiler and Pressure Vessel Code, 2013.

ASME B 31.3, *Process Piping,* 2012.

ASME B 31.5, *Refrigeration Piping,* 2013.

ASME B 31.8, *Gas Transmission and Distribution Piping Systems,* 2012.

2.3.6 ASTM Publications. ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959.

ASTM E84, *Standard Test Method for Surface Burning Characteristics of Building Materials*, 2012.

ASTM E136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C,* 2012.

ASTM E2652, *Standard Test Method for Behavior of Materials in a Tube Furnace with a Cone-shaped Airflow Stabilizer, at 750°C,* 2012.

2.3.7 CGA Publications. Compressed Gas Association, 14501 George Carter Way, Suite 103, Chantilly, VA 20151-2923.

CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids,* 2007.

CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Compressed Gas Storage Containers,* 2008.

2.3.8 CSA Publications. Canadian Standards Association, 5060 Spectrum Way, Mississauga, ON, L4W 5N6, Canada.

CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code,* 2009.

CSA C22.1, *Canadian Electrical Code,* 2012.

2.3.9 IEEE Publications. IEEE, Three Park Avenue, 17th Floor, New York, NY 10016-5997.

IEEE/ASTM SI 10, *American National Standard for Use of the International System of Units (SI): The Modern Metric System,* 2010.

2.3.10 NACE Publications. NACE International, 1440 South Creek Drive, Houston, TX 77084-4906.

NACE SP 0169, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems,* 2007.

2.3.11 UL Publications. Underwriters Laboratories, Inc., 333 Pfingsten Road, Northbrook, IL 60062–2096.

ANSI/UL 723, *Standard for Test for Surface Burning Characteristics of Building Materials*, 2008.

2.3.12 Other Publications.

American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety (CCPS), "Guidelines for Chemical Process Quantitative Risk Analysis," G-42, 2000 edition.

ASNT SNT-TC-IA, *Personnel Qualification and Certification in Nondestructive Testing,* 2011.

CEB Bulletin 187, *Concrete Structures Under Impact and Impulsive Loading,* International Federation for Structural Concrete, Switzerland, 1988.

EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and –165°C*, Parts 1–5, 2006.

European Norm Standard, BSI EN 31010:2010, "Risk Management–Risk Assessment Techniques."

Health and Safety Executive (HSE), "Risk Criteria for Land-use Planning in the Vicinity of Major Industrial Hazards," HMSO, HSE 1989 and "Five Steps to Risk Assessment," INDC 163, rev. 1, HSE 1998, United Kingdom.

Merriam-Webster's Collegiate Dictionary, 11th edition, Merriam-Webster, Inc., Springfield, MA, 2003.

TNO, "Guidelines for Quantitative Risk Assessment, RIVM, The Purple Book," Netherlands, 2005.

2.4 References for Extracts in Mandatory Sections.

NFPA 52, *Vehicular Gaseous Fuel Systems Code,* 2016 edition.
NFPA 54, *National Fuel Gas Code,* 2015 edition.
NFPA *101®* , *Life Safety Code®,* 2015 edition.

Chapter 3 Definitions

3.1 General. The definitions contained in this chapter shall apply to the terms used in this standard. Where terms are not defined in this chapter or within another chapter, they shall be defined using their ordinarily accepted meanings within the context in which they are used. *Merriam-Webster's Collegiate Dictionary*, 11th edition, shall be the source for the ordinarily accepted meaning.

3.2 NFPA Official Definitions.

3.2.1* Approved. Acceptable to the authority having jurisdiction.

3.2.2* Authority Having Jurisdiction (AHJ). An organization, office, or individual responsible for enforcing the requirements of a code or standard, or for approving equipment, materials, an installation, or a procedure.

3.2.3 Shall. Indicates a mandatory requirement.

3.2.4 Should. Indicates a recommendation or that which is advised but not required.

3.2.5 Standard. An NFPA Standard, the main text of which contains only mandatory provisions using the word "shall" to indicate requirements and that is in a form generally suitable for mandatory reference by another standard or code or for adoption into law. Nonmandatory provisions are not to be considered a part of the requirements of a standard and shall be located in an appendix, annex, footnote, informational note, or other means as permitted in the NFPA Manuals of Style. When used in a generic sense, such as in the phrase "standards development process" or "standards development activities," the term "standards" includes all NFPA Standards, including Codes, Standards, Recommended Practices, and Guides.

3.3 General Definitions.

3.3.1 Bunkering. The loading of a ship's bunker or tank with fuel for use in connection with propulsion or auxiliary equipment.

3.3.2 Cargo Tank Vehicle. A tank truck or trailer designed to transport liquid cargo.

3.3.3 Component. A part or a system of parts that functions as a unit in an LNG facility and could include, but is not limited to, piping, processing equipment, containers, control devices, impounding systems, electrical systems, security devices, fire control equipment, and communication equipment.

3.3.4 Container.

3.3.4.1 *Frozen Ground Container.* A container in which the maximum liquid level is below the normal surrounding grade, that is constructed essentially of natural materials, such as earth and rock, that is dependent on the freezing of water-saturated earth materials, and that has appropriate methods for maintaining its tightness or that is impervious by nature.

3.3.4.2 ***Prestressed Concrete Container.*** A concrete container where the concrete is placed into compression by internal or external tendons or by external wire wrapping.

3.3.4.3 ***Tank System.*** Low pressure (less than 15 psi) equipment designed for the purpose of storing liquefied natural gas consisting of one or more containers, together with various accessories, appurtenances, and insulation.

3.3.4.3.1* ***Double Containment Tank System.*** A single containment tank system surrounded by and within 20 ft (6 m) of a containment wall (secondary container) that is open to the atmosphere and designed to contain LNG in the event of a spill from the primary or inner container.

3.3.4.3.2* ***Full Containment Tank System.*** A tank system container in which the inner (primary) container is self standing and is surrounded by a separate self-standing secondary container designed to contain LNG in the event of a spill from the inner container, and the secondary container is enclosed by a steel or concrete roof designed such that excess vapor caused by a spill of LNG from the primary container will discharge through the relief valves.

3.3.4.3.3* ***Membrane Containment Tank System.*** A tank system consisting of a thin metal liquid barrier and load-bearing thermal insulation supported by a self-standing outer concrete container jointly forming an integrated composite tank structure designed to contain liquid and vapor during tank operation as well as LNG in the event of leakage from the liquid barrier, and where the vapor-containing roof of the outer container is either steel or concrete configured such that the excess vapor caused by a spill of LNG from the liquid barrier will discharge through the relief valves.

3.3.4.3.4* ***Single Containment Tank System.*** A single wall container or a double wall tank system in which only the self-supporting primary or inner container is designed to contain LNG.

3.3.5 Controllable Emergency. An emergency where operator action can minimize harm to people or property.

3.3.6 Design Pressure. The pressure used in the design of equipment, a container, or a pressure vessel for the purpose of determining the minimum allowable thickness or physical characteristics of its parts.

3.3.7 Dike. A structure used to establish an impounding area or containment. [**52,** 2016]

3.3.8* Engineering Design. Documentation governing the specification and design of components and systems within an LNG facility.

3.3.9 Fail-safe. A design feature that provides for the maintenance of safe operating conditions in the event of a malfunction of control devices or an interruption of an energy source.

3.3.10* Fire Protection. Fire prevention, fire detection, and fire suppression.

3.3.11 Fired Equipment. Any equipment in which the combustion of fuels takes place.

3.3.12 Flame Spread Index. A number obtained according to ASTM E84, *Standard Test Method for Surface Burning Characteristics of Building Materials*, or ANSI/UL 723, *Standard for Test for Surface Burning Characteristics of Building Materials*.

3.3.13 Hazardous Fluid. A liquid or gas that is flammable, toxic, or corrosive.

3.3.14 Impounding Area. An area defined through the use of dikes or the site topography for the purpose of containing any accidental spill of LNG or flammable refrigerants.

3.3.15 Liquefied Natural Gas (LNG). A fluid in the cryogenic liquid state that is composed predominantly of methane and that can contain minor quantities of ethane, propane, nitrogen, and other components normally found in natural gas.

3.3.16* LNG Facility. A collection of components used to produce, store, vaporize, transfer, or handle LNG.

3.3.17 LNG Plant. An LNG facility or collection of LNG facilities functioning as a unit.

3.3.18 Maximum Allowable Working Pressure (MAWP). The maximum gauge pressure permissible at the top of completed equipment, a container, or a vessel in its operating position for a design temperature.

3.3.19 Model. A mathematical characterization intended to predict a physical phenomenon.

3.3.20 Noncombustible Material. *See Section 4.6.* [***101,*** 2015].

3.3.21 Out-of-Service. The deactivation of a component for any purpose, including repairs or inspections.

3.3.22 Overfilling. Filling to a level above the maximum design liquid level.

3.3.23 Pipe Insulation Assembly. The set of materials used for insulation of pipes, including the insulation, outer jacket, vapor barrier and lap-seal adhesives.

3.3.24 Pressure Relief Device. A device designed to open to prevent a rise of internal pressure in excess of a specified value due to emergency or abnormal conditions.

3.3.25 Sources of Ignition. Appliances or equipment that, because of their intended modes of use or operation, are capable of providing sufficient thermal energy to ignite flammable gas–air mixtures. [**54,** 2015]

3.3.26 Tank Vehicle. See 3.3.2, Cargo Tank Vehicle.

3.3.27* Transfer Area. The portion of a liquefied natural gas (LNG) plant containing a piping system where LNG, flammable liquids, or flammable refrigerants are introduced into or removed from the plant or where piping connections are connected or disconnected routinely.

3.3.28 Transition Joint. A connector fabricated of two or more metals used to effectively join piping sections of two different materials that are not amenable to the usual welding or joining techniques.

3.3.29* Vacuum-Jacketed. A method of construction that incorporates an outer shell designed to maintain a vacuum in the annular space between the inner container or piping and outer shell.

3.3.30* Vaporizer.

3.3.30.1 ***Ambient Vaporizer.*** A vaporizer that derives its heat from naturally occurring heat sources, such as the atmosphere, seawater, or geothermal waters.

3.3.30.2 ***Heated Vaporizer.*** A vaporizer that derives heat for vaporization from the combustion of fuel, electric power, or waste heat, such as from boilers or internal combustion engines. [**52,** 2016]

3.3.30.2.1 ***Integral Heated Vaporizer.*** A vaporizer, including submerged combustion vaporizers, in which the heat source is integral to the actual vaporizing exchanger. [**52,** 2013]

3.3.30.2.2 ***Remote Heated Vaporizer.*** A heated vaporizer in which the primary heat source is separated from the actual vaporizing exchanger, and an intermediate fluid (e.g., water, steam, isopentane, glycol) is used as the heat transport medium.

3.3.30.3 ***Process Vaporizer.*** A vaporizer that derives its heat from another thermodynamic or chemical process to utilize the refrigeration of the LNG.

3.3.31 Water Capacity. The amount of water at 60°F (16°C) required to fill a container. [**52,** 2016]

Chapter 4 General Requirements

4.1 Scope. This chapter covers the general requirements for facilities covered under this standard.

4.2 Corrosion Control Overview.

4.2.1 Components shall not be constructed, repaired, replaced, or significantly altered until a qualified person 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.

4.2.2 The repair, replacement, or significant alteration of components shall be reviewed only if the action to be taken involves or is due to one of the following:

(1) A change in the original materials specified
(2) A failure caused by corrosion
(3) An inspection that reveals a significant deterioration of the component due to corrosion

4.3 Control Center.

4.3.1 Each LNG plant, other than those complying with Chapter 13, shall have a control center from which operations and warning devices are monitored as required by Section 4.3.

4.3.2 A control center shall have the following capabilities and characteristics:

(1) It shall be located apart from or be protected from other components so that it is operational during a controllable emergency.
(2) Each remotely actuated control system and each automatic shutdown control system required by this standard shall be operable from the control center.
(3) It shall have personnel in attendance while any of the components under its control are in operation, unless either the control is being performed from another control center that has personnel in attendance or the facility has an automatic emergency shutdown system.
(4) If more than one is located at an LNG plant, each control center shall have more than one means of communication with every other center.
(5) It shall have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel.

4.4 Sources of Power.

4.4.1 Electrical control systems, means of communication, emergency lighting, and fire-fighting systems shall have at least two sources of power that function so that failure of one source does not affect the capability of the other source.

4.4.2 Where auxiliary generators are used as a second source of electrical power, the following shall apply:

(1) They shall be located apart from or be protected from components so that they are not unusable during a controllable emergency.
(2) The fuel supply shall be protected from hazards.
(3) Where installed, emergency and/or standby power systems shall be installed in accordance with NFPA 110.

4.5 Records.

4.5.1 Each plant shall have a record of materials of construction for components, buildings, foundations, and support systems used for containment of LNG and flammable fluids.

4.5.2 The records shall verify that the material properties meet the requirements of this standard.

4.5.3 The records shall be maintained for the life of the components, buildings, foundations, and support systems.

4.6* Noncombustible Material. A material that complies with any of the following shall be considered a noncombustible material:

(1)* In the form in which it is used and under the conditions anticipated, it will not ignite, burn, support combustion, or release flammable vapors when subjected to fire or heat.
(2) It passes the noncombustible criterion of ASTM E136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C.*
(3) It passes the noncombustible criterion of ASTM E136 when tested in accordance with the test method and procedure in ASTM E2652, *Standard Test Method for Behavior of Materials in a Tube Furnace with a Cone-shaped Airflow Stabilizer, at 750°C.*

4.7 Ignition Source Control.

4.7.1 Smoking shall be permitted only in designated and signposted areas.

4.7.2 Welding, cutting, and hot work shall be conducted in accordance with the provisions of NFPA 51B.

4.7.3 Portable electric tools and extension lights capable of igniting LNG or other flammable fluids shall not be permitted within classified areas except where the area has been identified as free of flammable fluids.

4.7.4 Vehicles and other mobile equipment that constitute potential ignition sources shall be prohibited within diked areas or within 50 ft (15 m) of containers that contain LNG or other flammable fluids, except where authorized and at loading or unloading at facilities specifically designed for the purpose.

Chapter 5 Plant Siting and Layout

5.1 Scope. This chapter presents the criteria for plant and equipment siting.

5.2* Plant Site Provisions.

5.2.1 A written site evaluation addressing the following factors shall be prepared and made available to the authority having jurisdiction upon request:

(1) Potential incidents and mitigating measures
(2) Adjacent activities
(3) Severe weather patterns over a 100-year period
(4) Other natural hazards
(5) Security

5.2.2 All-weather accessibility to the plant for personnel safety and fire protection shall be provided except where provisions for personnel safety and fire protection are provided on the site in accordance with Chapter 12.

5.2.3 Site preparation shall include provisions for retention of spilled LNG, flammable refrigerants, and flammable liquids within the limits of plant property and for surface water drainage.

5.2.4* Soil and general investigations of the site shall be made to determine the design basis for the facility.

5.3 Site Provisions for Spill and Leak Control.

5.3.1 General.

5.3.1.1 Provisions shall be made to minimize the potential of accidental discharge of LNG at containers, pipelines containing LNG, and other equipment such that a discharge from any of these does not endanger adjoining property or important process equipment and structures or reach waterways. LNG containers shall be provided with one of the following methods to contain any release:

(1) An impounding area surrounding the container(s) that is formed by a natural barrier, dike, impounding wall, or combination thereof complying with 5.3.2 and 5.3.3
(2) An impounding area formed by a natural barrier, dike, excavation, impounding wall, or combination thereof complying with 5.3.2 and 5.3.3, plus a natural or man-made drainage system surrounding the container(s) that complies with 5.3.2 and 5.3.3
(3) Where the container is constructed below or partially below the surrounding grade, an impounding area formed by excavation complying with 5.3.2 and 5.3.3
(4) Secondary containment as required for double, full, or membrane containment tank systems complying with 5.3.2 and 5.3.3.

5.3.1.2 The following areas shall be graded, drained, or provided with impoundment in a manner that minimizes the possibility of accidental spills and leaks that could endanger important structures, equipment, or adjoining property or that could reach waterways:

(1) Process areas
(2) Vaporization areas
(3) Transfer areas for LNG, flammable refrigerants, and flammable liquids
(4) Areas immediately surrounding flammable refrigerant and flammable liquid storage tanks

5.3.1.3 If impounding areas also are required in order to comply with 5.2.3, such areas shall be in accordance with 5.3.2 and 5.3.3.

5.3.1.4 The provisions of 5.2.3, 5.3.1.1, and 5.3.1.2 that apply to adjoining property or waterways shall be permitted to be waived or altered at the discretion of the authority having jurisdiction where the change does not constitute a distinct hazard to life or property or conflict with applicable federal, state, and local (national, provincial, and local) regulations.

5.3.1.5 Flammable liquid and flammable refrigerant storage tanks shall not be located within an LNG container impounding area.

5.3.2 Impounding Area and Drainage System Design and Capacity.

5.3.2.1 Impounding areas serving one LNG container shall have a minimum volumetric holding capacity, V, that is one of the following:

(1) V = 110 percent of the maximum liquid capacity of the container
(2) V = 100 percent where the impoundment is designed to withstand the dynamic surge in the event of catastrophic failure of the container
(3) V = 100 percent where the height of the impoundment is equal to or greater than the container maximum liquid level

5.3.2.2 Impounding areas serving multiple LNG containers shall have a minimum volumetric holding capacity, V, in accordance with one of the following:

(1) V = 100 percent of the maximum liquid capacity of all containers in the impoundment area
(2) V = 110 percent of the maximum liquid capacity of the largest container in the impoundment area, where provisions are made to prevent leakage from any container due to exposure to a fire, low temperature, or both due to a leak from or fire on any other container in the shared impoundment

5.3.2.3 Enclosed drainage channels for LNG shall be prohibited except where they are used to rapidly conduct spilled LNG away from critical areas and they are sized for the anticipated liquid flow and vapor formation rates.

5.3.2.4 Where enclosed container down comers are used to rapidly conduct spilled LNG away from critical areas, they shall be sized for the anticipated liquid flow and vapor formation rates.

5.3.2.5* Dikes and impounding walls shall meet the following requirements:

(1) Dikes, impounding walls, drainage systems, and any penetrations thereof shall be designed to withstand the full hydrostatic head of impounded LNG or flammable refrigerant, the effect of rapid cooling to the temperature of the liquid to be confined, any anticipated fire exposure, and natural forces, such as earthquakes, wind, and rain.
(2) Where the outer shell of a tank system complies with the requirements of 5.3.1.1, the dike shall be either the outer shell or as specified in 5.3.1.1.

5.3.2.6 Double containment tank systems shall be designed and constructed such that in the case of a spill and secondary container fire, the secondary container wall will contain the LNG for the duration of the fire.

5.3.2.7 Double, full, and membrane containment tank systems shall be designed and constructed such that in the case of a fire in an adjacent tank, the secondary container shall retain sufficient structural integrity to prevent collapse, which can cause damage to and leakage from the primary container.

5.3.2.8 Double, full, and membrane containment tank systems shall have no pipe penetrations below the liquid level.

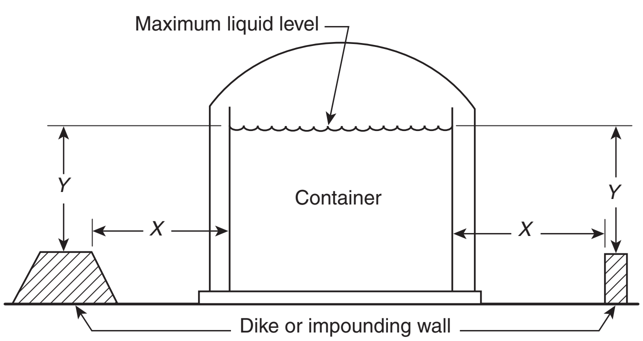
5.3.2.9 Dikes, impounding walls, and drainage channels for flammable liquid containment shall conform to NFPA 30.

5.3.2.10 Insulation systems used for impounding surfaces shall be, in the installed condition, noncombustible and suitable for the intended service, considering the anticipated thermal and mechanical stresses and loads. If flotation of the insulation can compromise its intended purpose, mitigating measures shall be provided.

5.3.2.11 The dike or impounding wall height and the distance from containers operating at 15 psi (103 kPa) or less shall be determined in accordance with Figure 5.3.2.11.

5.3.2.12 Water Removal.

5.3.2.12.1 Impoundment areas shall be constructed such that all areas drain completely to prevent water collection.



Notes:

- *X* is the distance from the inner wall of the container to the closest face of the dike or impounding wall.
- *Y* is the distance from the maximum liquid level in the container to the top of the dike or impounding wall.
- *X* equals or exceeds the sum of *Y* plus the equivalent head in LNG of the pressure in the vapor space above the liquid.

  Exception: When the height of the dike or impounding wall is equal to or greater than the maximum liquid level, X has any value.

FIGURE 5.3.2.11 Dike or Impoundment Wall Proximity to Containers.

(A) Drainage pumps and piping shall be provided to prevent water from collecting in the impoundment area.

(B) Impounding systems shall have sump pumps and piping running over the dike to remove water collecting in the sump basin.

5.3.2.12.2 The water removal system shall have capacity to remove water at a minimum of 25 percent of the rate from a storm of a 10-year frequency and 1-hour duration, except if the design of the dike does not allow the entrance of rainfall.

5.3.2.12.3 Sump pumps for water removal shall be as follows:

(1) Operated as necessary to keep the impounding space as dry as practical
(2) If sump pumps are designed for automatic operation, have redundant automatic shutdown controls to prevent operation when LNG is present

5.3.3 Impounding Area Siting.

5.3.3.1 The provisions of Section 5.3 shall not apply to impounding areas that serve only transfer areas at the water's edge of marine terminals.

5.3.3.2 The maximum radiant heat flux from a fire shall not exceed the limits listed in Table 5.3.3.2.

5.3.3.3* The use of passive fire mitigation techniques in the calculation of radiant heat distances shall be subject to the approval of the AHJ.

5.3.3.4* The distances to the radiant heat flux levels of Table 5.3.3.2 shall be calculated in accordance with a model that complies with all of the following:

(1) Takes into account the physical phenomena observed in, and has been validated with the data obtained from, available LNG fire experimental data, published in peer-reviewed scientific literature applicable to the physical situation considered
(2) Has been published in peer-reviewed scientific literature
(3) Has a scientific assessment verifying the details of the physics, analysis, and execution process
(4) Has been approved

5.3.3.5 Models employed in 5.3.3.4 shall incorporate the following:

(1) In calculating exclusion distances, 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.
(2) In calculating exclusion distances, the ambient temperature and relative humidity that produce the maximum exclusion distances shall be used except for values that occur less than 5 percent of the time, based on recorded data for the area.

5.3.3.6* The spacing of an LNG impoundment to the property line that can be built upon shall be such that, in the event of an LNG spill as specified in 5.3.3.7, a predicted concentration of methane in air of 50 percent of the lower flammability limit (LFL) does not extend beyond the property line that can be built upon, in accordance with a model that is acceptable for use by the authority having jurisdiction that has been evaluated by an independent body using the Model Evaluation Protocol facilities published by the Fire Protection Research

Table 5.3.3.2 Radiant Heat Flux Limits to Property Lines and Occupancies

Radiant Heat Flux		
Btu/hr/ft^2	W/m^2	Exposure
1,600	5,000	A property line at ground level that can be built upon for ignition of a design spill[a]
1,600	5,000	The nearest point located outside the owner's property line at ground level that, at the time of plant siting, is used for outdoor assembly by groups of 50 or more persons for a fire in an impounding area[b]
3,000	9,000	The nearest point on the building or structure outside the owner's property line that is in existence at the time of plant siting and used for assembly, educational, health care, detention and correction, or residential occupancies for a fire in an impounding area[b,c]
10,000	30,000	A property line at ground level that can be built upon for a fire over an impounding area[b]

[a]See 5.3.3.7 for design spill.
[b]The requirements for impounding areas are located in 5.3.2.
[c]See NFPA *101* or *NFPA 5000* for definitions of occupancies.

Foundation report "Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities."

(1) The computed distances shall include calculations based on one of the following:
   (a) The combination of wind speed and atmospheric stability that can occur simultaneously and result in the longest predictable downwind dispersion distance that is exceeded less than 10 percent of the time
   (b) The Pasquill-Gifford atmospheric stability, Category F, with a 4.5 mph (2 m/sec) wind speed
(2) The computed distances shall be based on the actual liquid characteristics and the maximum vapor outflow rate from the vapor containment volume (the vapor generation rate plus the displacement due to liquid inflow).
(3) The effects of provisions for detaining vapor or otherwise mitigating flammable vapor hazards (e.g., impounding surface insulation, water curtains, or other methods) shall be permitted to be considered in the calculation where acceptable to the authority having jurisdiction.
(4) Where provisions for detaining vapor or mitigating flammable vapor hazards are used, such as impounding surface insulation, water curtains, or other methods, they shall be approved.

5.3.3.7 The design spill shall be determined in accordance with Table 5.3.3.7.

5.3.3.8 LNG container impounding areas shall be located so that the heat flux from a fire over the impounding area shall not cause major structural damage to any LNG marine carrier that could prevent its movement.

5.3.3.9 Containers with an aggregate storage of 70,000 gal (265 m^3) or less on one site shall be installed either in accordance with 5.3.3 or in accordance with Table 5.3.4.1 where all connections are equipped with automatic fail-safe valves designed to close under any of the following conditions:

(1) Fire detection
(2) Excess flow of LNG from the container, as measured by loss of line pressure or other means
(3) Gas detection
(4) Manual operation from both a local and a remote location

(A) The appurtenances shall be installed as close to the container as practical and so that a break resulting from external strain occurs on the piping side of the appurtenance while retaining intact the valve and piping on the container side of the appurtenance.

(B) Connections used only for flow into the container shall be equipped with an automatic fail-safe valve or with two backflow check valves.

(C) Automatic fail-safe valves shall not be required for connections for relief valves and instrument valves.

(D) The type, quantity, and location of the detection devices shall be in accordance with the requirements of Chapter 12.

5.3.3.10 The distance from the nearest edge of impounded liquid to a property line that can be built upon or from the near edge of a navigable waterway as defined by federal regulations shall not be less than 50 ft (15 m).

5.3.4 Container Spacing.

5.3.4.1 The minimum separation distance between any type of LNG container of 70,000 gal (265 m^3) water capacity or less, single containment constructed LNG containers of greater than 70,000 gal (265 m^3) water capacity, or tanks containing flammable refrigerants and exposures shall be in accordance with Table 5.3.4.1 or with the approval of the authority having jurisdiction at a shorter distance from buildings or walls constructed of concrete or masonry but at least 10 ft (3.0 m) from any building openings.

5.3.4.2 Double, full, and membrane containment tank systems of greater than 70,000 gal (265 m^3) water capacity shall be separated from adjacent LNG storage containers such that a fire in an adjacent single or double containment impoundment or from a design spill will not cause loss of containment from adjacent containers. This shall be accomplished by ensuring that no part of the adjacent storage container roof, walls, or its impoundment structure reaches a temperature at which the strength of the material of the container roof, wall, or its impoundment is reduced to a level where the LNG tank, roof, or impoundment loses its structural integrity. The application of engineering analyses shall be used to determine this temperature by including the following conditions in the analyses:

(1) The analyses shall be performed for a fire involving the complete loss of containment of the primary liquid container to an impoundment area that complies with the requirements of 5.3.2.1

Table 5.3.3.7 Design Spill

Design Spill Source	Design Spill Criteria	Design Spill Rate and Volume
Containers with Penetrations Below the Liquid Level		
Containers with penetrations below the liquid level without internal shutoff valves	A spill through an assumed opening at, and equal in area to, that penetration below the liquid level resulting in the largest flow from an initially full container If more than one container in the impounding area, use the container with the largest flow	Use the following formula: $q = \frac{4}{3} d^2 \sqrt{h}$ until the differential head acting on the opening is 0. For SI units, use the following formula: $q = \frac{1.06}{10{,}000} d^2 \sqrt{h}$ until the differential head acting on the opening is 0.
Containers with penetrations below the liquid level with internal shutoff valves in accordance with 9.4.2.5	The flow through an assumed opening at, and equal in area to, that penetration below the liquid level that could result in the largest flow from an initially full container	Use the following formula: $q = \frac{4}{3} d^2 \sqrt{h}$ For SI units, use the following formula: $q = \frac{1.06}{10{,}000} d^2 \sqrt{h}$ for 10 minutes.
Containers with Over-the-Top Fill, with No Penetrations Below the Liquid Level		
Full or double containment containers with concrete secondary containers	No design spill	None
LNG Process Facilities		
Containers with over-the-top fill, with no penetrations below the liquid level	The largest flow from any single line that could be pumped into the impounding area with the container withdrawal pump(s) considered to be delivering the full-rated capacity	The largest flow from any single line that could be pumped into the impounding area with the container withdrawal pump(s) delivering the full rated capacity as follows: (1) For 10 minutes if surveillance and shutdown is demonstrated and approved by the authority having jurisdiction (2) For the time needed to empty a full container where surveillance and shutdown is not approved
Impounding areas serving only vaporization, process, or LNG transfer areas	The flow from any single accidental leakage source	For 10 minutes or for a shorter time based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction

Note: q = flow rate [ft^3/min (m^3/min)] of liquid; d = diameter [in. (mm)] of tank penetration below the liquid level; h = height [ft (m)] of liquid above penetration in the container when the container is full.

(2) The analyses shall account for the following:

(a) The duration of the fire, the radiant heat emission characteristics of the fire, and the physical attributes of the fire under the anticipated atmospheric conditions

(b) The atmospheric conditions producing the maximum separation distances shall be used except for conditions that occur less than 5 percent of the time based on recorded data for the area and using a LNG fire model in accordance with 5.3.3.4

(c) Active or passive systems to reduce thermal heat flux incident on the surface or to limit the surface temperature

(d) The materials, design, and methods of construction of the target LNG tank being analyzed

5.3.4.2.1 The outer concrete container shall be designed for the external fire in accordance with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, unless fire protection measures are provided. The outer tank thermal analysis shall be performed to determine temperature distribution for the heat flux and duration of exposure as specified in the fire risk assessment within API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*.

Table 5.3.4.1 Distances from Containers and Exposures

Container Water Capacity		Minimum Distance from Edge of Impoundment or Container Drainage System to Property Lines That Can Be Built Upon		Minimum Distance Between Storage Containers	
gal	m^3	ft	m	ft	m
<125*	<0.5	0	0	0	0
125–500	≥0.5–1.9	10	3	3	1
501–2,000	≥1.9–7.6	15	4.6	5	1.5
2,001–18,000	≥7.6–63	25	7.6	5	1.5
18,001–30,000	≥63–114	50	15	5	1.5
30,001–70,000	≥114–265	75	23		
>70,000	>265	0.7 times the container diameter but not less than 100 ft (30 m)		¼ of the sum of the diameters of adjacent containers [5 ft (1.5 m) minimum]	

*If the aggregate water capacity of a multiple container installation is 501 gal (1.9 m^3) or greater, the minimum distance must comply with the appropriate portion of this table, applying the aggregate capacity rather than the capacity per container. If more than one installation is made, each installation must be separated from any other installation by at least 25 ft (7.6 m). Do not apply minimum distances between adjacent containers to such installation.

(A) The applicable load components and the ultimate state load factors for the fire load combinations shall be in accordance with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, Table 7.3. For membrane tanks, an additional liquid pressure load in accordance with ACI 376, Table 7.2, shall be included.

(B) The design of the outer concrete container shall take into account the following factors:

(1) Reduction in the wall post-tensioning due to the difference in the coefficient of thermal expansion of post-tensioning steel and wall concrete at the temperature to which the post-tensioning steel is exposed, taking into consideration the effects of the concrete aggregate type on the concrete coefficient of thermal expansion
(2) Reduction in strength and modulus of elasticity of the outer tank concrete, reinforcing and post-tensioning steel due to elevated temperature
(3) Reduction in the wall post-tensioning due to pre-stressing steel softening and relaxation at elevated temperature

(C) The concrete wall, including the wall concrete mix, shall be designed to avoid explosive spalling.

5.3.4.3 The minimum separation distance between LNG containers and containers containing flammable refrigerants or from property lines that can be built upon shall be in accordance with Table 5.3.4.1.

5.3.4.4 A clear space of at least 3 ft (0.9 m) shall be provided for access to all isolation valves serving multiple containers.

5.3.4.5 LNG containers of greater than 125 gal (0.5 m^3) capacity shall not be located in buildings.

5.3.5 Vaporizer Spacing.

5.3.5.1 Vaporizers using flammable heat transfer fluids and their primary heat sources shall be located at least 50 ft (15 m) from any other source of ignition.

(A) Where more than one vaporizer is installed at one location, an adjacent vaporizer or primary heat source shall not be considered to be a source of ignition.

(B) Process heaters or other units of fired equipment shall not be considered to be sources of ignition with respect to vaporizer siting if they are interlocked so that they cannot be operated while a vaporizer is operating or while the piping system serving the vaporizer either is cooled down or is being cooled down.

5.3.5.2 Integral heated vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon *(see 5.3.5.4)* and at least 50 ft (15 m) from the following:

(1) Any impounded LNG, flammable refrigerant, or flammable liquid *(see 5.3.4)* or the paths of travel of such fluids between any other source of accidental discharge and the impounding area
(2) LNG, flammable liquid, flammable refrigerant, or flammable gas storage containers or tanks; unfired process equipment containing such fluids; or loading and unloading connections used in the transfer of such fluids
(3) Control buildings, offices, shops, and other occupied or important plant structures

5.3.5.3 Heaters or heat sources of remote heated vaporizers shall comply with 5.3.5.2.

5.3.5.4 Remote heated, ambient, and process vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon.

5.3.5.5 Vaporizers used in conjunction with LNG containers having a capacity of 70,000 gal (265 m^3) or less shall be located with respect to the property line in accordance with Table 5.3.4.1, assuming the vaporizer to be a container with a capacity equal to the largest container to which it is connected.

5.3.5.6 A clearance of at least 5 ft (1.5 m) shall be maintained between vaporizers.

5.3.6 Process Equipment Spacing.

5.3.6.1 Process equipment containing LNG, refrigerants, flammable liquids, or flammable gases shall be located at least 50 ft (15 m) from sources of ignition, a property line that can be built upon, control centers, offices, shops, and other occupied structures.

5.3.6.2 Where control centers are located in a building housing flammable gas compressors, the building construction shall comply with 5.4.3.

5.3.6.3 Fired equipment and other sources of ignition shall be located at least 50 ft (15 m) from any impounding area or container drainage system.

5.3.7 Loading and Unloading Facility Spacing.

5.3.7.1 A pier or dock used for pipeline transfer of LNG shall be located so that any marine vessel being loaded or unloaded is at least 100 ft (30 m) from any bridge crossing a navigable waterway.

5.3.7.2 The loading or unloading manifold shall be at least 200 ft (61 m) from such a bridge.

5.3.7.3 LNG and flammable refrigerant loading and unloading connections shall be at least 50 ft (15 m) from uncontrolled sources of ignition, process areas, storage containers, control buildings, offices, shops, and other occupied or important plant structures unless the equipment is directly associated with the transfer operation.

5.4 Buildings and Structures.

5.4.1 Buildings and Structures Design Classification. Buildings and structures shall be classified in accordance with the following:

(1)* Classification A — Buildings and structures as defined in 7.4.4.6(3)
(2) Classification B. — Buildings and structures supporting or enclosing equipment and piping that contain flammable or toxic materials
(3) Classification C — All other buildings and structures

5.4.2 Buildings and Structures Design. Buildings and structures shall be designed for seismic, wind, ice and snow in accordance with 5.4.2.1 through 5.4.2.3.

5.4.2.1 Classification A. Seismic design shall use the operating basis earthquake (OBE), safe shutdown earthquake (SSE), and aftershock level earthquake (ALE) ground motions as defined in 7.4.4.3through7.4.4.5 for determination of loads to be used per ASCE 7, *Minimum Design Loads for Buildings and Other Structures*; wind, ice, and snow design shall use an occupancy category of IV per ASCE 7.

5.4.2.2 Classification B. Seismic, wind, ice, and snow design shall use a risk category of III per ASCE 7.

5.4.2.3 Classification C. Seismic, wind, ice, and snow design shall use a risk category of II per ASCE 7.

5.4.3 Buildings or structural enclosures in which LNG, flammable refrigerants, and flammable gases are handled shall be of lightweight, noncombustible construction with non-load-bearing walls.

5.4.4 Rooms containing LNG and flammable fluids,if located within or attached to buildings in which such fluids are not handled (e.g., control centers, shops), shall be designed for fire and explosion control in accordance with the following:

(1) Deflagration venting shall be provided in accordance with NFPA 68.
(2) Common walls shall have no doors or other communicating openings
(3) Common walls shall have a fire-resistance rating of at least 1 hour.

5.4.5 Buildings or structural enclosures in which LNG, flammable refrigerants, and flammable gases are handled shall be ventilated to minimize the possibility of hazardous accumulations of flammable gases or vapors, in accordance with 5.4.5.1 through 5.4.5.4.

5.4.5.1 Ventilation shall be permitted to be by means of one of the following:

(1) A continuously operating mechanical ventilation system
(2) A combination gravity ventilation system and normally nonoperating mechanical ventilation system that is energized by combustible gas detectors in the event combustible gas is detected
(3) A dual rate mechanical ventilation system with the high rate energized by gas detectors in the event flammable gas is detected
(4) A gravity ventilation system composed of a combination of wall openings and roof ventilators
(5) Other approved ventilation systems

5.4.5.2 If there are basements or depressed floor levels, a supplemental mechanical ventilation system shall be provided.

5.4.5.3 The ventilation rate shall be at least 1 cfm of air per ft^2 (5 L/sec of air per m^2) of floor area.

5.4.5.4 If vapors heavier than air can be present, a portion of the ventilation shall be from the lowest level exposed to such vapors.

5.4.6 Buildings or structural enclosures not covered by 5.4.3 through 5.4.5 shall be located, or provision otherwise shall be made, to minimize the possibility of entry of flammable gases or vapors.

5.4.7* Buildings or structural enclosures not covered by 5.4.3 through 5.4.5 shall be designed, constructed, and installed to protect occupants against explosion, fire, and toxic material releases.

5.5* Designer and Fabricator Competence.

5.5.1 Supervision shall be provided for the fabrication of and for the acceptance tests of facility components to the extent necessary to ensure that they are structurally sound and otherwise in compliance with this standard.

5.5.2* Soil and general investigations shall be made to determine the adequacy of the intended site for the facility.

5.5.3 Designers, fabricators, and constructors of LNG facility systems and equipment shall be competent in their respective fields.

5.5.4 Supervision shall be provided for the fabrication, construction, and acceptance tests of facility components to verify that the facilities are structurally sound and otherwise in compliance with this standard.

5.6* Soil Protection for Cryogenic Equipment. LNG containers *(see 7.3.7)*, cold boxes, piping and pipe supports, and other cryogenic apparatus shall be designed and constructed to prevent damage to these structures and equipment due to freezing or frost heaving in the soil, or means shall be provided to prevent damaging forces from developing.

5.7 Falling Ice and Snow. Measures shall be taken to protect personnel and equipment from falling ice or snow that has accumulated on high structures.

5.8 Concrete Design and Materials.

5.8.1 Concrete used for construction of LNG containers shall be in accordance with 7.4.3.

5.8.2 Concrete structures that are normally or periodically in contact with LNG, including the foundations of cryogenic containers, shall be designed to withstand the design load, applicable environmental loadings, and anticipated temperature effects.

5.8.2.1 The design of the structures shall be in accordance with the provisions of 7.4.3.2.

5.8.2.2 The materials and construction shall be in accordance with the provisions of 7.4.3.2.

5.8.3 Structural concrete for pipe supports shall comply with Section 9.5.

5.8.4 Other Concrete Structures.

5.8.4.1 All other concrete structures shall be investigated for the effects of potential contact with LNG.

5.8.4.2 If failure of these structures would create a hazardous condition or worsen an existing emergency condition by exposure to LNG, the structures shall be protected to minimize the effects of such exposure, or they shall comply with 7.4.3.2.

5.8.5* Nonstructural concrete for incidental nonstructural uses, such as slope protection, impounding area paving, and other nonstructural slabs-on-grade, shall conform to ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*.

5.8.6 Minimum Reinforcement.

5.8.6.1 Reinforcement for concrete structures designed for LNG containment or cold vapor containment, other than those in 5.8.1 and 5.8.2; or for concrete structures covered in 5.8.3 and 5.8.4 shall be a minimum of 0.5 percent of the cross-sectional area of concrete for crack control in accordance with Appendix G of ACI 350, *Code Requirements for Environmental Engineering Concrete Structures*.

5.8.6.2 Minimum reinforcement for concrete for incidental nonstructural uses covered in 5.8.5 shall be in accordance with the shrinkage and temperature reinforcement provisions of ACI 318, *Building Code Requirements for Structural Concrete and Commentary*.

5.8.7 Concrete that is not constantly exposed to LNG and that has been subjected to sudden and unexpected exposure to LNG shall be inspected, and repaired if necessary, as soon as is practical after it has returned to ambient temperature.

5.9 Portable LNG Facility.

5.9.1 Where portable LNG equipment is used for temporary use, for service maintenance during gas systems repair or alteration, or for other short-term applications, the following requirements shall be met:

(1) Temporary portable LNG equipment shall not remain in service more than 180 days at the portable equipment installation. Portable installations in service more than 180 days shall meet one of the following requirements:
  (a) Approval by the AHJ to remain for a period exceeding 180 days
  (b) Compliance with all the applicable requirements of Chapter 13 for stationary applications using ASME containers and with the security requirements in Section 12.9
(2) LNG transport vehicles complying with U.S. Department of Transportation (DOT) requirements shall be used as the supply container.
(3) All portable LNG equipment shall be operated by at least one person qualified by experience and training in the safe operation of these systems in accordance with requirements in 14.9.3 and 14.9.4, based on the written training plan requirements in 14.9.1 and 14.9.2.
(4) All other operating personnel, at a minimum, shall be qualified by training in accordance with requirements in 14.9.3 and 14.9.4, based on the written training plan requirements in 14.9.1 and 14.9.2.
(5) All personnel requiring training in 5.9.1(2) and 5.9.1(3) shall receive refresher training in accordance with requirements in 14.9.6.1.
(6) All personnel training shall be documented in accordance with records requirements in 14.10.4.
(7) Each operator shall provide and implement a written plan of initial training in accordance with requirements in 14.9.1 and 14.9.2to instruct all designated operating and supervisory personnel.
(8) Provisions shall be made to minimize the possibility of accidental discharge of LNG at containers endangering adjoining property or important process equipment and structures or reaching surface water drainage.
(9) Portable or temporary containment means shall be permitted to be used.
(10) Vaporizers and controls shall comply with Section 8.3, 8.4.1, 8.4.2, 8.4.3.1, 8.4.6.1(1), 8.4.6.1(2), 8.4.7, and Section 8.5.
(11) Each heated vaporizer shall be provided with a means to shut off the fuel source remotely and at the installed location.
(12) Equipment and process design including piping, piping components, instrumentation and electrical systems, and transfer systems shall comply with Sections 4.5, 5.5; 6.3.1, 6.3.3, 6.3.4, 6.3.5, 6.5.1, 6.5.2, 6.5.4, 6.5.5, 9.2.1, 9.2.1.1, 9.2.1.2, 9.3.1.1, 9.3.1.2(3), 9.3.2.1 through 9.3.2.4, 9.3.3, 9.3.4; Sections 9.4 through 9.9; and if utilized, cryogenic pipe-in-pipe systems shall comply with Section 9.11, 10.7.1, 10.7.2, 10.7.6, 10.8.1, 11.4.1, 11.6.1, 11.6.2, 11.8.1, 11.8.2, 11.8.3, 11.8.6, 11.9.1, 11.9.2, 12.2.1, Section 12.3, and 12.3.3.

(13) The LNG facility spacing specified in Table 5.3.4.1 shall be maintained except where necessary to provide temporary service on a public right-of-way or on property where clearances specified in Table 5.3.4.1 are not feasible and where the following additional requirements are met:

(a) Traffic barriers shall be erected on all sides of the facility subject to passing vehicular traffic.
(b) The operation shall be continuously attended to monitor the operation whenever LNG is present at the facility.
(c) If the facility or the operation causes any restriction to the normal flow of vehicular traffic, in addition to the monitoring personnel required in 5.9.1(10), flag persons shall be continuously on duty to direct such traffic.

(14) Provision shall be made to minimize the possibility of accidental ignition in the event of a leak.
(15) Fire protection systems shall comply with 12.2.1, 12.3.1 through 12.3.6, 12.4.1, 12.4.2.2, 12.6.1, Section 12.7, 12.8.1, 12.9.1, and 12.9.2.
(16) Portable or wheeled fire extinguishers recommended by their manufacturer for gas fires shall be available at strategic locations and shall be provided and maintained in accordance with NFPA 10.
(17) Operating and maintenance activities shall comply with Sections 13.17, 14.1 through 14.4, 14.6.1, 14.6.2, 14.6.4, 14.6.5, 14.6.6.5 through 14.6.6.8, 14.6.6.8.3, 14.6.6.8.4, 14.6.6.8.5, Section 14.7, 14.8.1, 14.8.2, 14.8.6, 14.8.8, 14.8.9, 14.8.10.1, 14.8.10.2, 14.8.10.3, 14.8.10.7, 14.8.13.1, 14.8.13.4, and 14.8.13.13.
(18) The site shall be continuously attended, and provisions shall be made to restrict public access to the site whenever LNG is present.

5.9.2 If odorization is required of the temporary facility, the restrictions of 5.3.4.1 shall not apply to the location of odorizing equipment containing 20 gal (7.6 L) or less of flammable odorant within the retention system.

Chapter 6 Process Equipment

6.1 Scope. This chapter applies to the requirements for the design and installation of process equipment.

6.2 Installation of Process Equipment.

6.2.1 Process system equipment containing LNG, flammable refrigerants, or flammable gases shall be installed in accordance with one of the following:

(1) Outdoors, for ease of operation, to facilitate manual firefighting, and to facilitate dispersal of accidentally released liquids and gases
(2) Indoors, in enclosing structures that comply with 5.4.3 through 5.4.5

6.2.2 Welding and brazing of process equipment shall conform to the following:

(1) Welding and brazing of process equipment shall conform to the requirements of the standard to which the equipment is designed and constructed *(see 6.5.2 through 6.5.5)*. Where equipment is not constructed to a specific standard, welding and brazing shall be in accordance with the requirements in 6.2.2(2).
(2) All welding or brazing operations shall be performed with procedures qualified to Section IX of the ASME *Boiler and Pressure Vessel Code*.
(3) All welding or brazing shall be performed by personnel qualified to the requirements of Section IX of the ASME *Boiler and Pressure Vessel Code*.

6.3* Pumps and Compressors.

6.3.1 Pumps and compressors shall be constructed of materials selected for compatibility with the design temperature and pressure conditions.

6.3.2 Valving shall be installed so that each pump or compressor can be isolated for maintenance.

6.3.3 Where pumps or centrifugal compressors are installed for operation in parallel, each discharge line shall be equipped with a check valve.

6.3.4 Pumps and compressors shall be provided with a pressure-relieving device on the discharge to limit the pressure to the maximum design pressure of the casing and downstream piping and equipment, unless they are designed for the maximum discharge pressure of the pumps and compressors.

6.3.5 Each pump shall be provided with a vent, relief valve, or both that will prevent overpressuring of the pump case during the maximum possible rate of cooldown.

6.3.6 Compression equipment that handles flammable gases shall be provided with vents from all points where gases normally can escape. Vents shall be piped outside of buildings to a point of safe disposal.

6.4 Flammable Refrigerant and Flammable Liquid Storage. Installation of storage tanks for flammable refrigerants and liquids shall comply with NFPA 30, NFPA 58, NFPA 59, API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*; or Section 5.3 of this standard.

6.5 Process Equipment.

6.5.1 The maximum allowable working pressure shall be documented for process equipment.

6.5.2 Boilers shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section I, or with CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*.

6.5.3 Pressure vessels shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1 or Division 2, or with CSA B51, and shall be code-stamped.

6.5.4 Shell and tube heat exchangers shall be designed and fabricated in accordance with the ASME *Boiler Pressure Vessel Code*, Section VIII, Division 1, or with CSA B51, where such components fall within the jurisdiction of the pressure vessel code.

6.5.5 Brazed aluminum plate fin heat exchangers shall be designed and fabricated in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, and ALPEMA *Standards of the Brazed Aluminum Plate-Fin Heat Exchanger Manufacturers Association*.

6.5.6* Installation of internal combustion engines or gas turbines not exceeding 7500 horsepower per unit shall conform to NFPA 37.

6.5.7 A boil-off and flash gas-handling system separate from container relief valves shall be installed for the safe disposal of vapors generated in the process equipment and LNG containers.

6.5.7.1 Boil-off and flash gases shall discharge into a closed system or into the atmosphere so that they do not create a hazard to people, equipment, or adjacent properties.

6.5.7.2 The boil-off venting system shall be designed so that it cannot inspirate air during normal operation.

6.5.8 If internal vacuum conditions can occur in any piping, process vessels, cold boxes, or other equipment, either the piping and equipment subject to vacuum shall be designed to withstand the vacuum conditions or provision shall be made to prevent vacuum. If gas is introduced for the purpose of preventing a vacuum condition, it shall not create a flammable mixture within the system.

Chapter 7 Stationary LNG Storage

7.1 Scope. This chapter presents the requirements for the inspection, design, marking, testing, and operation of stationary LNG storage tank systems and ASME containers.

7.2 General.

7.2.1 Storage Tank Systems.

7.2.1.1 Storage tank systems, including membrane containment tank systems, shall comply with the requirements of API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, and the additional provisions of this chapter. The API 625 risk assessment shall be approved by the AHJ.

7.2.1.2 Metal containers that are part of an LNG storage tank system shall comply with API 620, *Design and Construction of Large, Welded, Low-Pressure Tanks*, and the further requirements in Section 7.4 below.

7.2.1.3 Concrete containers that are part of an LNG storage tank system shall comply with ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containments of Refrigerated Liquefied Gases*, and the requirements of Section 7.4.

7.2.1.4 The metallic membrane, load-bearing insulation, and the outer container moisture barrier specific to the membrane tank system shall comply with EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and −165°C*, Parts 1–5, for material selection, design, installation, examination, and testing and further requirements of Section 7.4. All other components of the membrane tank system shall comply with API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*; API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*; ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*; and additional requirements in Section 7.4.

7.2.1.5 All the membrane system components, including insulation, primary membrane, and the secondary barrier of the thermal protection system, shall be designed in such a way that they can withstand all possible static and dynamic actions throughout the tank lifetime.

7.2.1.6 Should any conflict exist among the requirements in 7.2.1.1 through 7.2.1.5, the most stringent requirement shall apply.

7.2.2 ASME Containers. ASME containers shall comply with the requirements of Section 7.5.

7.3 Design Considerations.

7.3.1 General.

7.3.1.1 Those parts of LNG containers that normally are in contact with LNG and all materials used in contact with LNG or cold LNG vapor [vapor at a temperature below −20°F (−29°C)] shall be physically and chemically compatible with LNG and intended for service at −270°F (−168°C).

7.3.1.2 All piping that is a part of an LNG tank system shall comply with requirements in this chapter and requirements within API 625*, Tank Systems for Refrigerated Liquefied Gas Storage*.

(A) Tank system piping shall include all piping internal to the container, within insulation spaces and within void spaces, external piping attached or connected to the container up to the first circumferential external joint of the piping, and external piping serving only tank instrumentation (including tank pressure relief valves). All liquid piping with a source of external line pressure shall be designed for the external line relief valve setting but not less than 50 psi (345 kPa). Double, full, and membrane containment tank systems shall have no pipe penetrations below the liquid level.

(B) Inert gas purge systems wholly within the insulation spaces and relief valve discharge piping shall be exempt from compliance.

(C) Piping that is a part of an ASME LNG container, including piping between the inner and outer containers, shall be in accordance with either the ASME *Boiler and Pressure Vessel Code*, Section VIII, or with ASME B 31.3, *Process Piping*.

(D) Compliance of piping which is part of the ASME container shall be stated on or appended to the ASME *Boiler and Pressure Vessel Code*, Appendix W, Form U-1, "Manufacturer's Data Report for Pressure Vessels."

7.3.1.3* All LNG tank systems shall be designed for both top and bottom filling unless other means are provided to prevent stratification.

7.3.1.4 Any portion of the outer surface area of an LNG tank system or external members whose failure could result in loss of containment from accidental exposure to low temperatures resulting from the leakage of LNG or cold vapor from flanges, valves, seals, or other nonwelded connections shall be designed for such temperatures or otherwise protected from the effects of low-temperature exposure.

7.3.1.5 Where two or more tank systems are sited in a common dike, each tank system foundation shall be capable of withstanding contact with LNG or shall be protected against contact with an accumulation of LNG that might endanger structural integrity.

7.3.1.6 The density of the liquid shall be assumed to be the actual mass per unit volume at the minimum storage temperatures, except that the minimum density for design purposes shall be 29.3 lb/ft^3 (470 kg/m^3).

7.3.1.7* Provisions shall be made for removal of the tank system from service.

7.3.2 Wind, Flood, and Snow Loads.

7.3.2.1 The wind, flood, and snow loads for the design of LNG tank systems and storage containers in the United States shall be determined using the procedures outlined in ASCE 7, *Minimum Design Loads for Buildings and Other Structures.*

7.3.2.2 For flood and snow loads, where a probabilistic approach is used, a 100-year mean occurrence interval shall be used.

7.3.2.3 Basic design wind speed shall be based on ASCE 7 for risk category IV structures.

7.3.2.4 The wind, flood, and snow loads used for the design of LNG storage containers in other countries shall be determined using either ASCE 7, or the values in the national code of the country.

7.3.3 Container Insulation.

7.3.3.1 Exposed insulation shall be noncombustible, shall contain or inherently shall be a vapor barrier, shall be water-free, and shall resist dislodgment by fire hose streams.

(A) Where an outer shell is used to retain loose insulation, the shell shall be constructed of steel or concrete.

(B) Exposed weatherproofing shall have a flame spread index not greater than 25. *(See 3.3.12.)*

7.3.3.2 The space between the inner container and the outer container shall contain insulation that is compatible with LNG and natural gas and that is noncombustible as installed for normal service and abnormal conditions.

(A) A fire external to the outer tank shall not cause a reduction to the internal containment system performance due to damage to any component of the insulation systems.

(B) The load-bearing bottom insulation shall be designed and installed so that cracking from thermal and mechanical stresses does not jeopardize the integrity of the container.

(C) For tank systems other than membrane containment tank system, only materials used between the inner and outer tank bottoms (floors) shall not be required to meet the combustibility requirements, where the material and the design of the installation comply with all of the following:

(1) The flame spread index of the material shall not exceed 25, and the material shall not support continued progressive combustion in air.
(2) The material shall be of such composition that surfaces that would be exposed by cutting through the material on any plane shall have a flame spread index not greater than 25 and shall not support continued progressive combustion.
(3) It shall be shown by test that the combustion properties of the material do not increase significantly as a result of long-term exposure to LNG or natural gas at the anticipated service pressure and temperature.
(4) The materials in the installed condition shall be demonstrated to be capable of being purged of natural gas.
(5) The natural gas remaining after purging shall not be significant and shall not increase the combustibility of the material.

(D) For membrane containment tank systems, the insulation system block shall include a non-foam cover (underneath the primary membrane) and shall include a welding thermal protection system in order to withstand all heat from welding during installation and during maintenance, if any.

7.3.3.3 Storage tank systems insulation shall meet the requirements of 625, Section 9.

7.3.4 Marking of LNG Storage Tank Systems and ASME Containers.

7.3.4.1 Each storage tank system shall be identified by the attachment in an accessible location of a corrosion-resistant nameplate as defined in API 625.

7.3.4.2 ASME containers shall be identified by the attachment of a corrosion resistant nameplate as required by *ASME Boiler and Pressure Vessel Code,* Section VIII.

7.3.4.3 Storage tank systems shall have all penetrations marked with the function of the penetration.

7.3.4.4 Penetration markings shall be visible if frosting occurs.

7.3.5 Container Drying, Purging, and Cooldown. Before an LNG tank system is put into service, it shall be dried, purged, and cooled in accordance with 14.3.5 and 14.5.5 and tank systems shall include the provisions within API 625 and/or ACI 376, as applicable to the type of tank construction.

7.3.6 Relief Devices.

7.3.6.1 All LNG tank systems shall be equipped with vacuum and pressure relief valves as required by the code or standard of manufacture.

7.3.6.2 Relief devices shall communicate directly with the atmosphere.

7.3.6.3 Vacuum-relieving devices shall be installed if the container can be exposed to a vacuum condition in excess of that for which the container is designed.

7.3.6.4 Each pressure and vacuum safety relief valve for LNG tank systems shall be able to be isolated from the tank systems for maintenance or other purposes by means of a manual full-opening stop valve.

(A) The stop valve(s) shall be lockable or sealable in the fully open position.

(B) Pressure and vacuum relief valves shall be installed on the LNG tank system to allow each relief valve to be isolated individually while maintaining the required relieving capacity.

(C) Where only one relief device is required, either a full-port opening three-way valve connecting the relief valve and its spare to the container or two relief valves separately connected to the container, each with a valve, shall be installed.

(D) No more than one stop valve shall be closed at one time.

(E) Safety relief valve discharge stacks or vents shall be designed and installed to prevent an accumulation of water, ice, snow, or other foreign matter and shall discharge vertically upward.

7.3.6.5 Pressure Relief Device Sizing.

7.3.6.5.1 The capacity of pressure relief devices shall be based on the following:

(1) Fire exposure
(2) Operational upset, such as failure of a control device
(3) Other circumstances resulting from equipment failures and operating errors
(4) Vapor displacement during filling
(5) Flash vaporization during filling, as a result of filling or as a consequence of mixing of products of different compositions
(6) Loss of refrigeration
(7) Heat input from pump recirculation
(8) Drop in barometric pressure

7.3.6.5.2 Pressure relief devices shall be sized to relieve the flow capacity determined for the largest single relief flow or any reasonable and probable combination of relief flows.

7.3.6.5.3* The minimum pressure-relieving capacity in pounds per hour (kilograms per hour) shall not be less than 3 percent of the full tank contents in 24 hours.

7.3.6.6 Vacuum Relief Sizing.

7.3.6.6.1 The capacity of vacuum relief devices shall be based on the following:

(1) Withdrawal of liquid or vapor at the maximum rate
(2) Rise in barometric pressure
(3) Reduction in vapor space pressure as a result of filling with subcooled liquid

7.3.6.6.2 The vacuum relief devices shall be sized to relieve the flow capacity determined for the largest single contingency or any reasonable and probable combination of contingencies, less the vaporization rate that is produced from the minimum normal heat gain to the container contents.

7.3.6.6.3 No vacuum relief capacity credit shall be allowed for gas-repressuring systems or vapor makeup systems.

7.3.6.7 Fire Exposure.

7.3.6.7.1 The pressure-relieving capacity required for fire exposure shall be computed by the following formulas:
For U.S. customary units:

[7.3.6.7.1a]

$$H = 34{,}500\ FA^{0.82} + H_n$$

For SI units:

[7.3.6.7.1b]

$$H = 71{,}000\ FA^{0.82} + H_n$$

where:
H = total heat influx [Btu/hr (watt)]
F = environmental factor from Table 7.3.6.7.1
A = exposed wetted surface area of the container [ft^2 (m^2)]
H_n = normal heat leak in refrigerated tanks [Btu/hr (watt)]

7.3.6.7.2 The exposed wetted area shall be the area up to a height of 30 ft (9 m) above grade.

7.3.6.7.3* Where used, insulation shall resist dislodgment by fire-fighting equipment, shall be noncombustible, and shall not decompose at temperatures up to 1000°F (538°C) in order for the environmental factor for insulation to be used.

Table 7.3.6.7.1 Environmental Factors

Basis	*F* Factor
Base container	1.0
Water application facilities	1.0
Depressuring and emptying facilities	1.0
Underground container	0
Insulation or thermal protection*	
U.S. customary units	$F = \dfrac{U(1660 - T_f)}{34{,}500}$
SI units	$F = \dfrac{U(904 - T_f)}{71{,}000}$

*U = overall heat transfer coefficient Btu/(hr · ft^2 ·°F) [W/(m^2 ·°C)] of the insulation system using the mean value for the temperature range from T_f to +1660°F (904°C); T_f = temperature of vessel content at relieving conditions, °F (°C).

7.3.6.7.4 Pressure Relief Valve Capacity.

(A) The relieving capacity shall be determined by the following formula:

[7.3.67.4(A)]

$$W = \frac{H}{L}$$

where:
W = relieving capacity of product vapor at relieving conditions [lb/hr (g/s)]
H = total heat influx, Btu/hr (watt)
L = latent heat of vaporization of the stored liquid at the relieving pressure and temperature, Btu/lb (J/g)

(B) The equivalent airflow shall be calculated from the following formulas:
For U.S. customary units:

[7.3.6.7.4(B)a]

$$Q_a = 3.09W\frac{\sqrt{TZ}}{\sqrt{M}}$$

For SI units:

[7.3.6.7.4(B)b]

$$Q_a = 0.93W\frac{\sqrt{TZ}}{\sqrt{M}}$$

where:
Q_a = equivalent flow capacity of air at 60°F (15°C) and absolute pressure of 14.7 psi (101 kPa) [ft^3/hr (m^3/hr)]
W = relieving capacity of product vapor at relieving conditions [lb/hr (g/s)]
T = absolute temperature of product vapor at relieving conditions [°R (K)]
Z = compressibility factor of product vapor at relieving condition
M = product vapor molecular mass [lbm/lb mol (g/g mol)]

7.3.7 Foundations.

7.3.7.1* LNG containers shall be installed on foundations designed by a qualified engineer and constructed in accordance with recognized structural engineering practices.

7.3.7.2 Storage tank systems foundations shall be designed in accordance with ACI 376.

7.3.7.3 Prior to the start of design and construction of the foundation, a subsurface investigation and evaluation shall be conducted by a soils engineer to determine the stratigraphy and physical properties of the soils underlying the site. A liquefaction evaluation in accordance with 11.8.3 of ASCE 7 shall be included as part of the above evaluation.

7.3.7.4 The bottom of the outer container shall be above the groundwater table or protected from contact with groundwater at all times.

7.3.7.5 The outer container bottom material in contact with soil shall meet one of the following requirements:

(1) Selected to minimize corrosion
(2) Coated or protected to minimize corrosion
(3)* Protected by a cathodic protection system

7.3.7.6 Where no air gap exists under the tank system foundation, a heating system shall be provided to prevent the 32°F (0°C) isotherm from penetrating the soil.

(A) The heating system shall be designed to allow functional and performance monitoring.

(B) Where there is a discontinuity in the foundation, such as for bottom piping, attention and separate treatment shall be given to the heating system in this zone.

(C) Heating systems shall be designed, selected, and installed so that any heating element and temperature sensor used for control can be replaced after installation.

(D)* Provisions shall be incorporated to prevent moisture accumulation in the conduit.

7.3.7.7 If the foundation is designed to provide air circulation in lieu of a heating system, the bottom of the outer container shall be of a material compatible with the temperatures to which it can be exposed.

7.3.7.8 A container bottom temperature monitoring system capable of measuring the temperature on a predetermined pattern over the entire surface area in order to monitor the performance of the bottom insulation and the container foundation heating system (if provided) shall be installed.

7.3.7.9 The system in 7.3.7.8 shall be used to conduct a container bottom temperature survey 6 months after the container has been placed in service and annually thereafter, after an operating basis earthquake (OBE), and after the indication of an abnormally cool area.

7.4 Tank Systems.

7.4.1 General.

7.4.1.1* Certification. Upon completion of all tests and inspections of each LNG tank system, the contractor shall certify to the purchaser that the LNG tank system has been constructed in accordance with the applicable requirements of this standard.

7.4.2 Metal Containers.

7.4.2.1 Welded containers designed for not more than 15 psi (103 kPa) shall comply with API 620.

7.4.2.2* API 620, Appendix Q, shall be applicable for LNG with the following changes. The frequency of examination by radiography or ultrasonic methods in primary and secondary liquid containers shall be increased to 100 percent for all butt welds in the cylindrical shell (except for the shell-to-bottom welds associated with a flat bottom container) and all butt-welded annular plate radial joints.

7.4.2.3 Weld Procedure and Production Weld Testing for Membrane Containment Tank Systems. For membrane containment tank systems, weld procedure and production weld testing shall comply with EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and −165°C*, Part 2, and the requirements in 7.4.2.3.1 through 7.4.2.3.5.

7.4.2.3.1 Qualification of Welders. All personnel associated with the welding fabrication of the membrane system shall be qualified by the manufacturer per an agreed-upon schedule between the purchaser, the AHJ, and the fabricator, and all records shall be available for review.

7.4.2.3.2 Inspection. One hundred percent of all welds shall be visually examined for workmanship and conformance to the fabrication requirements. The personnel performing the visual inspection shall be qualified to an accepted standard for this inspection work.

(A) Bead placement and consistency shall be, at a minimum, documented by digital means for review by supervisory personnel.

(B) Upon cooldown of the welds to room temperature, provisions shall be made to perform a penetrant inspection (PT) of at least 5 percent of each weld type each day; and the selection factors shall include orientation, welding direction, and the complexity of the welding being performed.

(1) All profiles and configurations of welds shall be subjected to the 5 percent requirement, and the selection of this 5 percent sample shall be agreed upon by the fabricator, the customer's representative, and the AHJ.
(2) The acceptance standard for this inspection technique shall be agreed upon by all parties.
(3) Any indication of a leak requires an additional 5 percent PT of the total distance welded by each welder.

(C) Inspection after completion of the membrane, which is the last step prior to the cooldown of the tank to service temperature, shall include a leakage test in parallel with a mechanical stress test as follows:

(1) Leakage shall be determined as agreed upon by the fabricator and the customer.
(2) Tracer gas for the leak test shall be in accordance with approved procedure.
(3) Mechanical stress testing of the welding joints shall be performed by applying three cycles from atmospheric pressure to +20 mbarg inside the insulation space, with the pressure maintained, for a minimum time of 30 minutes, and the data shall be recorded.

(4) All areas where leakage exceeds the limit shall be repaired and inspected per 7.4.2.3.2 and the manufacturer's approved procedure.

7.4.2.3.3 Post-Repair Inspection.

(A) Additional tracer gas testing shall be performed if more than four leaks per 1000 m^2 of membrane are identified.

(B) All repaired areas shall be visually inspected (VT), vacuum box (VB) tested, and dye penetrant (PT) tested.

7.4.2.3.4 Final Global Test. The final acceptance testing of the completed membrane structure following completion of its installation in the structural outer shell/container shall be in agreement with the approved test procedure and witnessed by all relevant parties and performed as follows:

(1) The overall tightness of the membrane shall be determined by establishing a pressure difference between the tank and the insulation space, which allows gas flow through the membrane representative of potential leaks on the membrane.
(2) The potential leak(s) shall be characterized by measuring the oxygen content increase in the primary insulated space as the tank is pressurized with dry air.
(3) The primary insulated space shall be regulated slightly above the atmospheric pressure.
(4) All test data, records, documentation, and witness records shall be submitted to all parties for review and final acceptance.

7.4.2.3.5 Control During Removal of Construction Equipment. A daily tightness check and monitoring shall be performed during removal of construction equipment by pulling vacuum inside insulated spaces. Any pressure rise, which is indicative of a leak, shall be reported and corrective action shall be taken.

7.4.3 Concrete Containers.

7.4.3.1 The design, construction, inspection, and testing of concrete containers shall comply with ACI 376.

7.4.3.2 Tanks with unlined concrete primary liquid containment shall include a means of detecting and eliminating liquid accumulation in the annular space.

7.4.3.3 Non-metallic coatings placed on a concrete container acting as a moisture and/or product vapor barrier shall meet the criteria in ACI 376.

7.4.3.4 Metallic barriers incorporated in, and functioning compositely with, concrete containers shall be of a metal defined in API 620, Appendix Q.

7.4.4 Seismic Design of Land-Based Field-Fabricated Tank Systems.

7.4.4.1 A site-specific investigation shall be performed for all installations except those provided for in 7.5.2 to determine the characteristics of seismic ground motion and associated response spectra.

(A) The site-specific investigation performed in accordance with ASCE 7, Chapter 21 shall account for the regional seismicity and geology, the expected recurrence rates and maximum magnitudes of events on known faults and source zones, the location of the site with respect to these seismic sources, near source effects, if any, and the characteristics of subsurface conditions.

(B) On the basis of the site-specific investigation, the ground motion of a maximum considered earthquake (MCE_R) shall be the motion having a 2 percent probability of exceedance within a 50-year period (mean recurrence interval of 2475 years), adjusted by the requirements of ASCE 7, Chapter 21.

(C) For the MCE_R ground motion, vertical and horizontal acceleration response spectra shall be constructed covering the entire range of anticipated damping ratios and natural periods of vibration, including the fundamental period and damping ratio for the sloshing (convective) mode of vibration of the contained LNG.

(D) The MCE_R response spectral acceleration for any period, *T*, shall correspond to a damping ratio that best represents the structure being investigated as specified in API 620, Appendix L, and ACI 376, Chapter 6.

(E) If information is not available to develop a vertical response spectrum, the ordinates of the vertical response spectrum shall not be less than two-thirds of those of the horizontal spectrum. If information is available, the corresponding ratio shall not be less than one-half.

7.4.4.2 The LNG tank systems and their impounding systems shall be designed for the following three levels of seismic ground motion:

(1) Safe shutdown earthquake (SSE) as defined in 7.4.4.3
(2) Operating basis earthquake (OBE) as defined in 7.4.4.4
(3) Aftershock level earthquake (ALE) as defined in 7.4.4.5

7.4.4.3 The SSE shall be represented by a ground motion response spectrum in which the spectral acceleration at any period, *T*, shall be equal to the spectral acceleration of the MCE_R ground motion defined in 7.4.4.1.

7.4.4.4* The OBE ground motion shall be the motion represented by an acceleration response spectrum having a 10 percent probability of exceedance within a 50-year period (mean return interval of 475 years). In the United States, the OBE spectra can be developed from the U.S. Geological Survey (USGS) national seismic maps or from site-specific probabilistic seismic hazard analysis. If a site-specific analysis is carried out, the OBE spectra shall not be less than 80 percent of the USGS spectra adjusted for local site conditions.

7.4.4.5 The ALE ground motion is defined as one-half SSE.

7.4.4.6 The three levels of ground motion defined in 7.4.4.3 through 7.4.4.5 shall be used for the earthquake-resistant design of the following structures and systems:

(1) LNG tank systems and their impounding systems
(2) System components required to isolate the LNG tank system and maintain it in a safe shutdown condition
(3) Structures or systems, including fire protection systems, the failure of which could affect the integrity of 7.4.4.6(1) or 7.4.4.6(2)

(A) The structures and systems shall be designed to remain operable during and after an OBE.

(B) The OBE design shall be based on a response reduction factor equal to 1.0.

(C) The SSE design shall provide for no loss of containment capability of the primary container of single, double, and full containment tank systems and of the metal liquid barrier of membrane tank systems, and it shall be possible to isolate and maintain the LNG tank systems during and after the SSE.

(D) Where used, response reduction factors applied in the SSE design shall be demonstrated not to reduce the performance criteria in 7.4.4.6(C). The values in API 620, Appendix L, are deemed to comply.

7.4.4.7 The secondary liquid container or impounding system for single, double, or full containment tanks shall, as a minimum, be designed to withstand an SSE while empty and an ALE while holding a volume equivalent to the primary containment liquid at the maximum normal operating level as defined in API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*.

7.4.4.8 For the membrane tank system, all components of the product-containing structure, including the liquid barrier, insulation system, thermal corner protection system *(see 7.4.7.1)*, and the outer concrete tank, shall be designed to withstand without failure an SSE event with the tank filled to the maximum normal operating level. The outer concrete tank and the thermal corner protection shall be designed to withstand an ALE with a tank full to the maximum normal operating level assuming that the membrane has failed and that the outer tank wall and thermal corner protection system are exposed to LNG.

7.4.4.9 An LNG tank system shall be designed for the OBE, SSE, and ALE in accordance with API 620 and ACI 376.

7.4.4.10 After an event exceeding OBE, the tank system shall be evaluated for safe continued operation. After an SSE event, the container shall be emptied and inspected prior to resumption of container-filling operations.

7.4.4.11 The design of the LNG tank systems and structural components shall be in accordance with API 620 or ACI 376. Soil-structure interaction (SSI) shall be included where the tank system is not founded on bedrock (Site Class A or B per ASCE 7). SSI is permitted to be performed in accordance with the requirements of ASCE 7, Chapter 19.

7.4.4.12 The outer concrete tank analysis and design for the leak and leak plus ALE event shall take into account any damage that might have occurred to the outer concrete tank due to prior events, including the SSE earthquake.

(A) The outer concrete tank shall be considered as undamaged during the prior SSE event if the following conditions are met:

(1) Tensile stresses in the reinforcing steel do not exceed 90 percent of the reinforcing steel yield.
(2) Maximum concrete compressive stresses do not exceed 85 percent of the concrete design compressive strength.

(B) If the conditions in 7.4.4.12(A) are not met, the prior damage shall be taken into account in the spill analysis.

7.4.4.13 Instrumentation capable of measuring the ground motion to which tank systems are subjected shall be provided on the site.

7.4.5 Inspection.

7.4.5.1 Prior to initial operation, tank systems shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of this standard.

7.4.5.2 The inspection shall be conducted by inspectors who are employees of the operator, an engineering or scientific organization, or a recognized insurance or inspection company.

7.4.5.3 Inspectors shall be qualified in accordance with the code or standard applicable to the container and as specified in this standard.

7.4.6 Testing of LNG Containers.

7.4.6.1 LNG primary containers shall be hydrostatically tested and leak tested in accordance with the governing construction code or standard, and all leaks shall be repaired.

7.4.6.2 LNG concrete primary containers shall be hydrotested to a liquid height equal to the design liquid height times the product design specific gravity times 1.25 and applying an overload pressure of 1.25 times the pressure for which the vapor space is designed.

7.4.6.3 The tank system designer shall provide a test procedure based on the applicable construction standard.

7.4.6.4 After acceptance tests are completed, there shall be no field welding on the LNG containers, except as permitted in 7.4.6.4(A) and (B).

(A) Field welding shall be limited to saddle plates or brackets provided for the purpose and to repairs permitted under the code or standard of fabrication.

(B) Retesting by a method appropriate to the repair or modification shall be required only where the repair or modification is of such a nature that a retest actually tests the element affected and is necessary to demonstrate the adequacy of the repair or modification.

7.4.6.5* Membrane containment tank systems shall be tested in accordance with EN 14620, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed, steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and –165°C*, Part 5, Table 1, as follows:

(1) The leakage test, as defined in the Note under EN 14620, Part 5, paragraph 4.1.1, shall be performed.
(2) Leakage through the membrane to the insulation space during service shall be controlled in order to maintain a gas concentration level below 30 percent of the lower explosive limit (LEL) by sweeping the insulated space with an inert gas.
(3) If the gas concentration cannot be maintained below 30 percent of the LEL, the tank shall be decommissioned and retested.
(4) For purposes of evaluating the 30 percent level, the flow of purge gas within the annular space shall not be increased above the normal operating rate.

7.4.6.6 Verification of all components of the membrane containment tank system design by experimental data from model tests shall be carried out.

7.4.7 Additional Requirements for Membrane Containment Tank Systems.

7.4.7.1 A thermal corner protection system functionally equivalent to the thermal corner protection system for concrete tanks (as defined in API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, Section 6, and if required by ACI 376, *Code Requirements for Design and Construction of Concrete Structures for* *the Containment of Refrigerated Liquefied Gases*) shall be provided for the outer concrete tank of the membrane tank system.

(A) The thermal corner protection shall protect the entire bottom of the outer tank and at least the lower 16.5 ft (5 m) of the wall from thermal shock and shall be liquidtight when it is in contact with LNG and vapor-tight in all conditions.

(B) The thermal corner protection system shall be permitted to be either metallic or made from nonmetallic materials compatible with LNG and shall maintain structural integrity and liquid/gas tightness under all applicable mechanical and thermal loads.

(C) The membrane containment tank system supplier shall provide tests independently witnessed and verified by a third-party agency clearly demonstrating the leak-tightness of all the thermal corner system under spill conditions. Historical tests shall be acceptable provided that construction processes and materials of construction are the same as those proposed.

(D) Nondestructive examination (NDE) performed on the secondary barrier and NDE acceptance criteria shall ensure that the provided tightness is equivalent to the tightness provided by the metallic thermal corner protection system of the full containment tank system.

7.4.7.2 The outer concrete container of the membrane containment tank system shall meet all requirements of ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, for the secondary concrete container, including materials, design, construction, inspection, and testing and the additional requirements specified in 7.4.7.2.1 through 7.4.7.2.5.

7.4.7.2.1 The pressure of the liquid product shall be a design load for the outer concrete tank. The liquid-product pressure ultimate limit state (ULS) load factors for operating and abnormal loading conditions shall be in accordance with Table 7.2 of ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*.

7.4.7.2.2 The outer concrete container wall and slab-to-wall junction shall be checked for fatigue assuming four full load-unload cycles a week for the expected life of the tank. Performance criteria of ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*, Appendix C, shall apply.

7.4.7.2.3 The outer concrete container wall shall resist the specified impact load without perforation and scabbing.

(A) The concrete wall thickness shall be at least 40 percent greater than the scabbing depth calculated per CEB 187, *Concrete Structures Under Impact and Impulsive Loading — Synthesis Report*, Section 4.1.2.2.

(B) The concrete wall thickness shall be at least 20 percent greater than the perforation thickness calculated per CEB 187, Section 4.1.1.1.

(C) The concrete wall shall be designed so that either one of the following conditions is satisfied:

(1) The distance between the outer face of the concrete container and the centroid of the pre-stressing tendons is greater than the penetration depth calculated per CEB 187, Section 4.1.2.1, with the following allowances for uncertainty:
    (a) 20 percent thicker than the penetration depth where $z > 0.75$
    (b) 50 percent thicker than the penetration depth where $z \leq 0.75$
(2) The concrete wall is designed to be able to resist normal operating loads with any one horizontal tendon completely ineffective.

(D) For concrete walls post-tensioned with a wire wrapping system, the wall shall be designed to resist normal operating loads with the wires affected by a specified impact load considered completely ineffective. No unwrapping of the post-tensioning wires shall be allowed.

7.4.7.2.4 At a minimum, the outer concrete container for the membrane tank system shall meet the construction tolerances specified in ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*. Where more stringent tolerances are required by the membrane and insulation systems, those more stringent tolerances shall be specified by the membrane tank engineer and met by the tank contractor.

7.4.7.2.5 The outer concrete container shall be hydrotested prior to membrane and insulation installation following the primary container hydrotest requirements of API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, Section 10.

7.5 ASME Containers Designed for Operation at More Than 15 psi (103 kPa).

7.5.1 General.

7.5.1.1 Containers shall be double-walled, with the inner tank holding the LNG surrounded by insulation contained in the outer tank.

7.5.1.2 The insulation shall be evacuated or purged.

7.5.1.3 The inner tank shall be of welded construction and in accordance with Section VIII of the ASME *Boiler and Pressure Vessel Code* and shall be ASME-stamped and registered with the National Board of Boiler and Pressure Vessel Inspectors or other agencies that register pressure vessels.

(A) Where vacuum is utilized for insulation purposes, the design pressure of the inner tank shall be the sum of the required working pressure (absolute), and the hydrostatic head of LNG.

(B) Where vacuum is not utilized as part of the insulation, the design pressure shall be the sum of the required working gauge pressure and the hydrostatic head of LNG.

(C) The inner container shall be designed for the most critical combination of loading resulting from internal pressure and liquid head, the static insulation pressure, the insulation pressure as the container expands after an in-service period, the purging and operating pressure of the space between the inner and outer containers, and seismic loads.

7.5.1.4 The outer container shall be of welded construction.

(A) The following materials shall be used:

(1) Any of the carbon steels in Section VIII, Part UCS of the ASME *Boiler and Pressure Vessel Code* at temperatures at or above the minimum allowable use temperature in Table 1A of the ASME *Boiler and Pressure Vessel Code*, Section II, Part D

(2) Materials with a melting point below 2000°F (1093°C) where the container is buried or mounded

(B) Where vacuum is utilized for insulation purposes, the outer container shall be designed by either of the following:

(1) The ASME *Boiler and Pressure Vessel Code*, Section VIII, Parts UG-28, UG-29, UG-30, and UG-33, using an external pressure of not less than 15 psi (103 kPa)
(2) Paragraph 3.6.2 of CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*

(C) Heads and spherical outer containers that are formed in segments and assembled by welding shall be designed in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Parts UG-28, UG-29, UG-30, and UG-33, using an external pressure of 15 psi (103 kPa).

(D) The maximum allowable working pressure shall be specified for all components.

(E) The outer container shall be equipped with a relief device or other device to release internal pressure, as follows:

(1) The discharge area shall be at least 0.00024 in.^{2}/lb (0.34 mm^2/kg) of the water capacity of the inner container, but the area shall not exceed 300 in.^{2} (0.2 m^2).
(2) The relief device shall function at a pressure not exceeding the internal design pressure of the outer container, the external design pressure of the inner container, or 25 psi (172 kPa), whichever is least.

(F) Thermal barriers shall be provided to prevent the outer container from falling below its design temperature.

(G) Saddles and legs shall be designed to withstand loads anticipated during shipping and installation, and seismic, wind, and thermal loads.

(H) Foundations and supports shall be protected to have a fire resistance rating of at least 2 hours.

(I) If insulation is used to achieve the fire resistance rating of at least 2 hours, it shall be resistant to dislodgment by fire hose streams.

7.5.1.5 Stress concentrations from the support system shall be minimized by the use of such items as pads and load rings.

7.5.1.6 The expansion and contraction of the inner container shall be included in the stress calculations, and the support system shall be designed so that the resulting stresses imparted to the inner and outer containers are within allowable limits.

7.5.1.7 Internal piping between the inner container and the outer container and within the insulation space shall be designed for the maximum allowable working pressure of the inner container, with allowance for thermal stresses.

(A) Bellows shall not be permitted within the insulation space.

(B) Piping shall be of materials satisfactory for −278°F (−172°C) as determined by the ASME *Boiler and Pressure Vessel Code*.

(C) No liquid line external to the outer container shall be of aluminum, copper, or copper alloy, unless it is protected against a 2-hour fire exposure.

(D) Transition joints shall not be prohibited.

7.5.1.8 The inner container shall be supported concentrically within the outer container by either a metallic or a nonmetallic system that is capable of sustaining the maximum loading of either of the following:

(1) Shipping load supports shall be designed for the maximum acceleration to be encountered, multiplied by the empty mass of the inner container.
(2) Operating load supports shall be designed for the total mass of the inner container plus the maximum loading, which shall include the following:
    (a) Seismic factors shall be included.
    (b) The mass of contained liquid shall be based on the maximum density of the specified liquid within the range of operating temperatures, except that the minimum density shall be 29.3 lb/ft^3 (470 kg/m^3).

7.5.1.9 The allowable design stress in support members shall be the lesser of one-third of the specified minimum tensile strength or five-eighths of the specified minimum yield strength at room temperature. Where threaded members are used, the minimum area at the root of the threads shall be used.

7.5.2 Seismic Design of Land-Based Shop-Built Containers.

7.5.2.1 Shop-built containers designed and constructed in accordance with the ASME *Boiler and Pressure Vessel Code* and their support system shall be designed for the dynamic forces associated with horizontal and vertical accelerations as follows: For horizontal force, V:

[7.5.2.1a]

$$V = Z_c \times W$$

For design vertical force, P:

[7.5.2.1b]

$$P = \frac{2}{3} Z_c \times W$$

where:

Z_c = seismic coefficient equal to 0.60 S_{DS} , where S_{DS} is the maximum design spectral acceleration determined in accordance with the provisions of ASCE 7, using an importance factor, I, of 1.0, for the site class most representative of the subsurface conditions where the LNG facility is located

W = total weight of the container and its contents

(A) This method of design shall be used only when the natural period, T, of the shop-built container and its supporting system is less than 0.06 second.

(B) For periods of vibration greater than 0.06 second, the method of design in 7.4.4 shall be followed.

7.5.2.2 The container and its supports shall be designed for the resultant seismic forces in combination with the operating loads, using the allowable stress increase shown in the code or standard used to design the container or its supports.

7.5.2.3 The requirements of 7.5.2 shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

7.5.2.4 Instrumentation capable of measuring the ground motion to which containers are subjected shall be provided on the site.

7.5.3 Filling Volume. Containers designed to operate at a pressure in excess of 15 psi (103 kPa) shall be equipped with a device(s) that prevents the container from becoming liquid-full or from covering the inlet of the relief device(s) with liquid when the pressure in the container reaches the set pressure of the relieving device(s) under all conditions.

7.5.4 Testing of ASME LNG Containers.

7.5.4.1 Containers designed for gauge pressures in excess of 15 psi [103 kPa] shall be tested in accordance with the following:

(1) Shop-fabricated containers shall be pressure tested by the manufacturer prior to shipment to the installation site.
(2) The inner container shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or with CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code*.
(3) The outer container shall be leak tested.
(4) Piping shall be tested in accordance with Section 9.7.
(5) Containers and associated piping shall be leak tested prior to filling the container with LNG.

7.5.4.2 The inner container of field-fabricated containers designed for gauge pressures in excess of 15 psi [103 kPa] shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or CSA B51.

7.5.4.3 The outer container of field-fabricated containers designed for gauge pressures in excess of 15 psi [103 kPa] shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or CSA B51.

Chapter 8 Vaporization Facilities

8.1* Scope. This chapter presents the design, construction, and installation requirements for LNG vaporizers.

8.2 Classification of Vaporizers.

8.2.1 If the temperature of the naturally occurring heat source of an ambient vaporizer exceeds 212°F (100°C), the vaporizer shall be considered to be a remote heated vaporizer.

8.2.2 If the naturally occurring heat source of an ambient vaporizer is separated from the actual vaporizing heat exchanger and a controllable heat transport medium is used between the heat source and the vaporizing exchanger, the vaporizer shall be considered to be a remote heated vaporizer and the provision for heated vaporizers shall apply.

8.3 Design and Materials of Construction.

8.3.1* Vaporizers shall be designed, fabricated, and inspected in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII.

8.3.2 Vaporizer heat exchangers shall be designed for a working pressure at least equal to the maximum discharge pressure of the LNG pump or the pressurized container system supplying them, whichever is greater.

8.4 Vaporizer Piping, Intermediate Fluid Piping, and Storage Valves.

8.4.1 Manifolded vaporizers shall have both inlet and discharge block valves at each vaporizer.

8.4.2 The discharge valve of each vaporizer and the piping components and relief valves installed upstream of each vaporizer discharge valve shall be designed for operation at LNG temperatures [−260°F (−162°C)].

8.4.3 Isolation of an idle manifolded vaporizer shall be by two inlet valves.

8.4.3.1 The LNG or gas that can accumulate between the valves or other double-block-and-bleed systems shall be piped to an area having no source of ignition and where people are not present.

8.4.4 A shutoff valve shall be installed on the LNG line to a vaporizer at least 50 ft (15 m) from the vaporizer.

8.4.4.1 If the vaporizer is installed in a building, the shutoff valve shall be installed at least 50 ft (15 m) from the building.

8.4.4.2 The shutoff valve shall be either the container shutoff valve or another valve.

8.4.5 Each heated or process vaporizer shall be provided with a local and a remote device to shut off the heat source.

8.4.5.1 Where the heated or process vaporizer is located 50 ft (15 m) or more from the heat source, the remote shutoff location shall be at least 50 ft (15 m) from the vaporizer.

8.4.5.2* Where the heated vaporizer is located less than 50 ft (15 m) from the heat source, it shall have an automatic, fire-safe shutoff valve in the LNG liquid line that closes when any of the following occurs:

(1) Loss of line pressure (excess flow)
(2) Fire in the immediate vicinity of the vaporizer or shutoff valve
(3) Low temperature in the vaporizer discharge line

8.4.5.3 If the LNG plant is attended, manual operation of the automatic shutoff valve shall be from a point at least 50 ft (15 m) from the vaporizer, in addition to the requirements in 8.4.5.2.

8.4.6* Any vaporizer installed within 50 ft (15 m) of an LNG container shall be equipped with an automatic, fire-safe shutoff valve in the LNG liquid line.

8.4.6.1 The automatic shutoff valve shall close in any one of the following situations:

(1) Loss of line pressure (excess flow)
(2) Fire in the immediate vicinity of the vaporizer or shutoff valve
(3) Low temperature in the vaporizer discharge line

8.4.6.2 If the LNG plant is attended, manual operation of the automatic shutoff valve shall be from a point at least 50 ft (15 m) from the vaporizer, in addition to the requirements of 8.4.6.1.

8.4.7 Automatic equipment shall be provided to prevent the discharge of either LNG or vaporized gas into a piping system at a temperature either above or below the design temperatures of the system.

8.4.7.1 Automatic equipment shall be independent of all other flow control systems.

8.4.7.2 Automatic equipment shall incorporate a line valve for emergency purposes.

8.4.8 Where a flammable intermediate fluid is used with a remote heated or process vaporizer, shutoff valves shall be in accordance with the following:

(1) Shutoff valves shall be provided on both the hot and the cold lines of the intermediate fluid system.
(2) Shutoff valve controls shall be located at least 50 ft (15 m) from the vaporizer.

8.5 Relief Devices on Vaporizers.

8.5.1 The relief valve capacity of heated or process vaporizers shall be selected to provide discharge capacity of 110 percent of rated vaporizer natural gas flow capacity without allowing the pressure to rise more than 10 percent above the vaporizer maximum allowable working pressure.

8.5.2 The relief valve capacity for ambient vaporizers shall be selected to provide relief valve discharge capacity of at least 150 percent of rated vaporizer natural gas flow capacity based on standard operating conditions, without allowing the pressure to rise more than 10 percent above the vaporizer maximum allowable working pressure.

8.5.3 Relief valves on heated vaporizers shall be located so that they are not subjected to temperatures exceeding 140°F (60°C) during normal operation unless the valves are designed to withstand higher temperatures.

8.6 Combustion Air Supply. Combustion air required for the operation of integral heated vaporizers or the primary heat source for remote heated vaporizers shall be taken from outside a completely enclosed structure or building.

8.7 Products of Combustion. Where integral heated vaporizers or the primary heat source for remote heated vaporizers are installed in buildings, provisions shall be made to prevent the accumulation of hazardous products of combustion.

Chapter 9 Piping Systems and Components

9.1* Scope. This chapter presents the design, construction, installation, examination, and inspection requirements for process piping systems and components.

9.2 General.

9.2.1* Process piping systems within the scope of ASME B 31.3, *Process Piping,* except those that are part of or within an LNG Container shall be in accordance with ASME B 31.3.

9.2.1.1 The additional provisions of this chapter supplement those in ASME B 31.3 and shall apply to piping systems and components for flammable liquids and flammable gases.

9.2.1.2 Fuel gas systems shall be in accordance with NFPA 54 or ASME B 31.3.

9.2.1.3 Fire protection system piping shall meet the applicable NFPA standards in Section 2.2.

9.2.2 Seismic Design Requirements.

9.2.2.1 For purposes of design, all piping of the LNG plant shall be classified into one of the following three seismic categories:

(1) Category I — All piping supported by the LNG container and piping up to the emergency shutdown valve(s) and firewater piping
(2) Category II — All flammable gas or LNG process piping
(3) Category III — All other piping not included in Categories I and II

9.2.2.2 Piping categories shall be in accordance with the following:

(1) Category I — All Category I piping shall be designed for the OBE and SSE event. For the OBE design, response modifications shall not be used.
(2) Category II — All Category II piping shall be designed for the design earthquake per ASCE 7, *Minimum Design Loads for Buildings and Other Structures.* At maximum, a response modification factor R_p of 6 shall be used. The importance value I_p shall be taken as 1.5.
(3) Category III — All Category III piping shall be designed for the design earthquake per ASCE 7.

9.2.2.3 Piping shall be analyzed using an equivalent static analysis or a dynamic analysis meeting the requirements of ASCE 7. The OBE, SSE, and design earthquake loads shall be combined with other loads using the load combination of ASCE 7. The stiffness of pipe supports in the direction of applied restraint shall be included in the pipe stress analysis model unless the supports can be qualified as rigid according to the following criteria:

(1) Supports with 12 in. (0.3 m) and larger pipe: minimum support stiffness of 100 kips/in. (1797 kg/mm) in the direction of restraint
(2) Supports with 12 in. (0.3 m) and smaller pipe: minimum support stiffness of 10 kips/in. (179.7 kg/mm) in the direction of restraint

9.2.3* Piping systems and components shall be designed to accommodate the effects of fatigue resulting from the thermal cycling to which the systems are subjected.

9.2.4 Provision for expansion and contraction of piping and piping joints due to temperature changes shall be in accordance with ASME B 31.3, Section 319.

9.3 Materials of Construction.

9.3.1 General.

9.3.1.1 All piping materials, including gaskets and thread compounds, shall be selected for compatibility with the liquids and gases handled throughout the range of temperatures to which they are subjected.

9.3.1.2 Piping, including gasketed joints, that can be exposed to the low temperature of an LNG or refrigerant spill or the heat of an ignited spill during an emergency where such exposure could result in a failure of the piping that would increase the emergency shall be one of the following:

(1) Made of material(s) that can withstand both the normal operating temperature and the extreme temperature to which the piping might be subjected during the emergency

(2) Protected by insulation or other means to delay failure due to such extreme temperatures until corrective action can be taken by the operator
(3) Capable of being isolated and having the flow stopped where piping is exposed only to the heat of an ignited spill during the emergency

9.3.1.3 Piping insulation used in areas where the mitigation of fire exposure is necessary shall have a maximum flame spread index of 25 when tested in accordance with ASTM E 84, *Standard Test Method for Surface Burning Characteristics of Building Materials,* or ANSI/UL 723, *Standard for Test for Surface Burning Characteristics of Building Materials,* and shall maintain those properties that are necessary to maintain physical and thermal integrity during an emergency when exposed to fire, heat, cold, or water.

9.3.1.4* In addition to 9.3.1.3, pipe insulation assemblies used in areas where the mitigation of fire exposure is necessary shall be one of the following:

(1) Comprised of noncombustible materials per ASTM E 136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C (see Section 4.6)*
(2) Covered by an outer protective stainless steel jacket at least 0.02 in. (0.51 mm) thick
(3) Covered by an outer aluminum jacket at least 0.032 in. (0.81 mm) thick
(4) Determined to meet the conditions of acceptance in B.3 of NFPA 274

9.3.2 Piping.

9.3.2.1 Furnace lap-welded and furnace butt-welded pipe shall not be used.

9.3.2.2 All piping material shall either meet the requirements in Chapter III of ASME B 31.3 or conform with ASME B 31.3, paragraphs 323.1.2 and 323.2.3 and be documented in the engineering design.

9.3.2.3 All piping components shall either meet the requirements in Chapter III of ASME B 31.3 or conform with ASME B 31.3, paragraphs 326.1.2 and 326.2.2 and be documented in the engineering design.

9.3.2.4 Threaded pipe shall be at least Schedule 80.

9.3.2.5 A liquid line on a storage container, cold box, or other insulated equipment external to the outer shell or jacket, whose failure can release a significant quantity of flammable fluid, shall not be made of aluminum, copper or copper alloy, or material with a melting point of less than 2000°F (1093°C).

9.3.2.5.1 Bottom penetration liquid lines on single containment tanks with aluminum inner tanks and cold boxes utilizing aluminum heat exchangers shall be permitted to use aluminum piping to the point where the thermal distance piece transitions to stainless steel or other materials meeting the requirements of 9.3.2.5.

9.3.2.6 Transition Joints.

(A) Transition joints shall be protected against fire exposure. Thermal distance pieces from storage tanks, coldboxes, and similar equipment shall not be insulated if insulation will diminish the effectiveness of the thermal distance piece.

(B) Protection against fire exposure shall not be required for liquid lines protected against fire exposure and loading arms and hoses.

9.3.2.7 Cast iron, malleable iron, and ductile iron pipe shall not be used.

9.3.3 Fittings.

9.3.3.1 Threaded nipples shall be at least Schedule 80.

9.3.3.2 Cast iron, malleable iron, and ductile iron fittings shall not be used.

9.3.3.3* Bends.

(A) Bends shall be permitted only in accordance with ASME B 31.3, Section 332. Corrugated and creased bends shall be prohibited.

(B) Field bending shall not be permitted on any 300 series stainless steel or other cryogenic containment materials or components, except instrument tubing with a minimum design temperature less than −20°F (−29°C) unless:

(1) Performed in accordance with the engineering design
(2) Performed using mechanical or hydraulic equipment and tools specifically designed for bending pipe
(3) The examination requirements of paragraphs 332.1 and 332.2.1 in ASME B 31.3 are used to verify each bend
(4) All bending and forming of piping material shall meet the requirements of ASME B 31.3, Section 332, except that corrugated and creased bends shall be prohibited

9.3.3.4 Solid plugs or bull plugs made of at least Schedule 80 seamless pipe shall be used for threaded plugs.

9.3.3.5 Compression-type couplings shall not be used where they can be subjected to temperatures below −20°F (−29°C), unless they meet the requirements of ASME B 31.3, Section 315.

9.3.4 Valves.

9.3.4.1 Valves shall comply with one of the following:

(1) ASME B 31.3, paragraph 307.1.1
(2) ASME B 31.5, *Refrigeration Piping*; ASME B 31.8, *Gas Transmission and Distribution Piping Systems*; or API 6D, *Specification for Pipeline Valves,* where suitable for the design conditions
(3) ASME B 31.3, paragraph 307.1.2, where documented in the engineering design

9.3.4.2 Cast iron, malleable iron, and ductile iron valves shall not be used.

9.4 Installation.

9.4.1 Piping Joints.

9.4.1.1 Pipe joints of 2 in. (50 mm) nominal diameter or less shall be threaded, welded, or flanged.

9.4.1.2 Pipe joints larger than 2 in. (50 mm) nominal diameter shall be welded or flanged.

9.4.1.3 Tubing joints shall be in accordance with paragraph 315 in ASME B 31.3.

9.4.1.4 The following pipe joints are prohibited:

(1) Expanded joints per ASME B 31.3, paragraph 313
(2) Caulked joints per ASME B 31.3, paragraph 316
(3) Special joints per ASME B 31.3, paragraph 318

9.4.1.5 Special components that are unlisted per ASME B 31.3 paragraph 304.7.2 shall be based on design calculations consistent with the design criteria of ASME B 31.3. Calculations shall be substantiated by one or both of the means stated in ASME B 31.3, paragraph 304.7.2 (a), paragraph 304.7.2(b), or both.

9.4.1.6 Where necessary for connections to equipment or components, where the connection is not subject to fatigue-producing stresses, joints of 4 in. (100 mm) nominal diameter or less shall be threaded, welded, or flanged.

9.4.1.7 The number of threaded or flanged joints shall be minimized and used only where necessary, such as at material transitions or instrument connections, or where required for maintenance.

9.4.1.8 Where threaded joints are used, they shall be seal welded or sealed by other means proven by test except for the following:

(1) Instrument connections where the heat from welding would cause damage to the instrument
(2) Where seal welding would prevent access for maintenance
(3) Material transitions where seal welding is not practical

9.4.1.9 Dissimilar metals shall be joined by flanges or transition joint techniques that have been proven by test at the intended service conditions.

9.4.1.10 Where gaskets are subject to fire exposure, they shall be resistant to fire exposure.

9.4.2* Valves.

9.4.2.1 Extended bonnet valves shall be installed with packing seals in a position that prevents leakage or malfunction due to freezing.

9.4.2.2 Where the extended bonnet in a cryogenic liquid line is installed at an angle greater than 45 degrees from the upright vertical position, it shall be demonstrated to be free of leakage and frost under operating conditions.

9.4.2.3 Shutoff valves shall be installed on container, tank, and vessel connections, except for the following:

(1) Connections for relief valves in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1, UG-125(d) and Appendix M-5
(2) Connections for liquid level alarms as required by 10.2.1.3 or 13.15.2 if an ASME container
(3) Connections that are blind flanged or plugged

9.4.2.4 Shutoff valves shall be located inside the impoundment area as close as practical to such containers, tanks, and vessels where provided.

9.4.2.5 The design and installation of an internal valve shall be such that any failure of the penetrating nozzle resulting from external pipe strain is beyond the shutoff seats of the internal valve itself.

9.4.2.6 In addition to the container shutoff valve required in 9.4.2.3, container connections larger than 1 in. (25 mm) nominal diameter and through which liquid can escape shall be equipped with at least one of the following:

(1)* A valve that closes automatically if exposed to fire
(2) A remotely controlled, quick-closing valve that remains closed except during the operating period
(3) A check valve on filling connections

9.4.2.7 Valves and valve controls shall be designed to allow operation under icing conditions where such conditions can exist.

9.4.2.8 Powered and manual operators shall be provided for emergency shutoff valves 8 in. (200 mm) or larger.

9.4.2.9* Where power-operated valves are installed, the closure time shall not produce a hydraulic shock capable of causing stresses that can result in piping or equipment failure.

9.4.2.10 A piping system used for periodic transfer of cold fluid shall be provided with a means for precooling before transfer.

9.4.2.11 Check valves shall be installed in designated one-directional transfer systems to prevent backflow and shall be located as close as practical to the point of connection to any system from which backflow might occur.

9.4.3 Welding and Brazing. All pressure containment, ASME B 31.3 piping, and component welding and brazing in or for any LNG facility shall be in accordance to Section IX of the ASME *Boiler and Pressure Vessel Code*.

9.4.3.1 Qualification and performance of welders shall be in accordance with subsection 328.2 of ASME B 31.3, and 9.4.3.2 of this standard.

9.4.3.2 For the welding of impact-tested materials, qualified welding procedures shall be selected to minimize degradation of the low-temperature properties of the pipe material.

9.4.3.3 For the welding of attachments to unusually thin pipe, procedures and techniques shall be selected to minimize the danger of burn-through.

9.4.3.4 Oxygen–fuel gas welding shall not be permitted.

9.4.3.5 Brazing and brazed connections shall be in accordance with subsections 317.2 and 333 of ASME B 31.3.

9.4.3.6 Brazed connections which are part of an ASME B 31.3 piping system shall be limited to a minimum service temperature of −20°F (−29°C) and warmer. The system shall be in accordance with Appendix G, Safeguarding, of ASME B 31.3. Brazed connections used for service temperatures colder than −20°F (−29°C) shall be specified in the engineering design and approved by the operator.

9.4.4* Pipe Marking. Markings on pipe shall comply with the following:

(1) Markings shall be made with a material compatible with the pipe material.
(2) Materials less than ¼ in. (6.4 mm) in thickness shall not be die stamped.
(3) Marking materials that are corrosive to the pipe material shall not be used.

9.5 Pipe Supports.

9.5.1 Pipe supports, including any insulation systems used to support pipe whose stability is essential to plant safety, shall be resistant to or protected against fire exposure, escaping cold liquid, or both, if they are subject to such exposure.

9.5.2 Pipe supports for cold lines shall be designed to minimize heat transfer, which can result in piping failure by ice formations or embrittlement of supporting steel.

9.5.3 The design of supporting elements shall conform to ASME B 31.3, Section 321.

9.6* Piping Identification. Piping shall be identified by color coding, painting, or labeling.

9.7 Inspection, Examination, and Testing of Piping. Inspection, examination, and testing shall be performed in accordance with Chapter VI of ASME B 31.3 to demonstrate sound construction, installation and leak tightness. Unless specified otherwise in the engineering design, piping systems for flammable liquids and flammable gases shall be examined and tested per the requirements of ASME B 31.3, Normal Fluid Service.

9.7.1 Leak Testing.

9.7.1.1 Leak testing shall be conducted in accordance with ASME B 31.3, Section 345.

9.7.1.2 To avoid possible brittle failure, carbon and low-alloy steel piping shall be leak tested at metal temperatures suitably above their nil ductility transition temperature.

9.7.2 Record Keeping.

9.7.2.1 A record of each leak test shall be made per paragraph 345.2.7 of ASME B 31.3.

9.7.3 Welded Pipe Examinations.

9.7.3.1 Longitudinal welded pipe that is subjected to minimum design temperatures below −20°F (−29°C) shall meet the following requirement:

(1) The longitudinal or spiral weld shall be subjected to 100 percent radiographic examination in accordance with paragraph 302.3.4 and Table A-1B of ASME B 31.3 to provide a basic longitudinal weld joint Quality Factor E_j of 1.0 or as allowed in Table 302.3.4 for E_j equal to 1.0.

9.7.3.2 All circumferential butt-and-miter groove welds and branch connection welds comparable to Figure 328.5.4E in ASME B 31.3 subjected to minimum design temperatures below −20°F (−29°C) shall be examined fully by radiographic or ultrasonic examination in accordance with Chapter VI, Sections 341 and 344, of ASME B 31.3 except as modified by 9.7.3.2(A) and 9.7.3.2(B).

(A) Liquid drain and vapor vent piping with an operating pressure that produces a hoop stress of less than 20 percent specified minimum yield stress shall not be required to be nondestructively tested if it has been inspected visually in accordance with ASME B 31.3, subsection 344.2.

(B) Piping with minimum design temperature at or above -20°F (-29°C) shall have random 20 percent radiographic or ultrasonic examination of circumferential butt-and-miter groove welds and branch connection welds comparable to Figure 328.5.4E in accordance with Chapter VI, Sections 341 and 344 of ASME B 31.3.

9.7.3.3 All socket welds and fillet welds, for piping with a design minimum temperature below −20°F (−29°C), including internal and external attachment welds, shall be 100 percent examined visually and by liquid penetrant or magnetic particle examination in accordance with Chapter VI, Sections 341 and 344, of ASME B 31.3.

9.7.3.4* All branch connection welds not radiographed or ultrasonically examined, shall be 100 percent examined per ASME B 31.3, Chapter VI, Sections 341 and 344, as follows:

(1) For piping with design temperatures below −20°F (−29°C), all branch connections shall be 100 percent visually examined and by liquid penetrant or magnetic particle examination.
(2) For piping with design temperatures at or above −20°F (−29°C), all branch connections shall be 100 percent visually examined.

9.7.4 Examination Criteria.

9.7.4.1 Nondestructive examination methods, limitations on defects, and the qualifications of the personnel performing and interpreting the examinations shall meet the requirements of ASME B 31.3, Chapter VI, Sections 341 through 344, and the following:

(1) The requirements of Normal Fluid Service shall apply as a minimum for examination acceptance criteria, unless specified otherwise in the engineering design.
(2) Personnel performing nondestructive examinations (NDE) shall, as a minimum, be qualified Level I per ASNT SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing,* or an equivalent qualification standard.
(3) Personnel interpreting nondestructive examinations shall, as a minimum, be qualified Level II per ASNT SNT-TC-1A or an equivalent qualification standard.
(4) NDEs shall be performed in accordance with written procedures meeting all the requirements of ASME *Boiler and Pressure Vessel Code*, Section V, as applicable to the specific NDE method.

9.7.4.2 Substitution of in-process examination for radiographic or ultrasonic examination as permitted in ASME B 31.3, Paragraph 341.4.1, shall be permitted on a weld-for-weld basis only if specified in the engineering design, specifically approved by the operator, and supplemented by the following additional nondestructive examinations:

(1) 100 percent liquid penetrant or magnetic particle examination shall be performed at the lesser of one-half the weld thickness or each ½ in. (12.5 mm) of weld thickness.
(2) 100 percent liquid penetrant or magnetic particle examination shall be performed on all accessible final weld surfaces.

9.7.5 Record Retention.

9.7.5.1 Test and examination records and written procedures required within this standard and within ASME B 31.3, Paragraph 345.2.7 and Section 346 respectively, shall be maintained for the life of the piping system by the facility operator or until such time as a re-examination is conducted.

9.7.5.2 Records and certification pertaining to materials, components, and heat treatment as required by ASME B 31.3, Paragraph 341.4.1(c), 341.4.3(d), and Section 346 shall be maintained by the facility operator for the life of the system.

9.8 Purging of Piping Systems.

9.8.1 Blow-down and purge connections shall be provided to facilitate purging of all process piping and all flammable gas piping.

9.9 Safety and Relief Valves.

9.9.1 Pressure-relieving safety devices shall be arranged so that the possibility of damage to piping or appurtenances is reduced to a minimum.

9.9.1.1 Safety relief systems (piping and valves) shall be designed, installed, and tested in accordance with ASME B 31.3, subsection 322.6, and Section 9.9 of this standard in its entirety.

9.9.2 The means for adjusting relief valve set pressure shall be sealed.

9.9.3 A thermal expansion relief valve shall be installed to prevent overpressure in any section of a liquid or cold vapor pipeline that can be isolated by valves.

9.9.3.1 A thermal expansion relief valve shall be set to discharge at or below the design pressure of the line it protects.

9.9.3.2 Discharge from thermal expansion relief valves shall be directed to minimize hazard to personnel and other equipment.

9.10 Corrosion Control.

9.10.1* Underground and submerged piping shall be protected and maintained in accordance with the principles of NACE SP 0169, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems.*

9.10.2 Austenitic stainless steels and aluminum alloys shall be protected to minimize corrosion and pitting from corrosive atmospheric and industrial substances during storage, construction, fabrication, testing, and service.

9.10.2.1 Tapes or other packaging materials that are corrosive to the pipe or piping components shall not be used.

9.10.2.2 Where insulation materials can cause corrosion of aluminum or stainless steels, inhibitors or waterproof barriers shall be utilized.

9.11 Cryogenic Pipe-in-Pipe Systems.

9.11.1 General. The design of cryogenic pipe shall address the following issues:

(1) Seismic, geotechnical concerns, installation, and the concern that the pipe be designed to perform its function without failure
(2) Dynamic loading and static loading conditions of both the inner and outer pipes
(3) Maximum relative motion between the inner and outer pipes

9.11.2 Inner Pipe. The inner pipe assembly shall be designed, fabricated, examined, and tested in accordance with ASME B 31.3, and inspection levels shall be specified. As a minimum, Normal Fluid Service requirements shall be met, unless specified otherwise in the engineering design.

9.11.3 Outer Pipe. The outer pipe assembly shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B 31.3.

9.11.3.1 As a minimum, Normal Fluid Service requirements shall be met, unless specified otherwise in the engineering design.

9.11.3.2 If the outer pipe also functions as the secondary containment system, the outer pipe shall be designed to contain the inner pipe product and shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B 31.3.

9.11.4 Vacuum-Jacketed Function. If the outer pipe functions as a vacuum-jacketed system, then failure of the outer pipe shall not damage the inner pipe.

9.11.4.1 If the outer jacket functions as the secondary containment system, the outer pipe jacket shall be designed to withstand and carry the full inner pipe product and shall be designed, fabricated, examined, and tested in accordance with the requirements of ASME B 31.3.

9.11.5 Annular Space. The annular space and inner pipe support system shall be designed to minimize thermal conductance and heat loss.

9.11.5.1 All components in the annular space shall be selected to minimize long-term degradation of the insulation system.

9.11.5.2 The vacuum level, if any, shall be specified.

9.11.6 Operational Requirements.

9.11.6.1 If the pipe-in-pipe is vacuum-jacketed, provisions shall be made to allow verification of vacuum levels and methods of reapplication of vacuum. If the pipe-in-pipe is not vacuum-jacketed, provision shall be made to allow circulation of inert gas in the annulus.

9.11.6.2 Provisions shall be made for temperature monitoring.

(A) Where the pipe-in-pipe is a vacuum-jacketed pipe, the temperature of the outer skin of the vacuum jacket shall be monitored.

(B) Where the pipe-in-pipe is not vacuum jacketed, the temperature in the annulus shall be monitored.

(C) Visual inspection shall be acceptable for aboveground installations.

9.11.7 Connections. Mechanical connectors shall be designed to maintain the thermal, structural, and installation conditions present on the pipe segments it is connecting.

9.11.8* Corrosion Protection.

9.11.8.1 The inner pipe and the annular space shall be considered to be noncorroding in its operating environment.

9.11.8.2 The outer pipe shall be designed or protected in accordance with NACE standards to mitigate potential corrosion.

9.11.9 Installation.

9.11.9.1 Pipe, when buried on land, shall be buried to a minimum of 3 ft (0.9 m) of cover.

9.11.9.2 Pipe, when buried in navigable waterways should be buried to minimum depth of 4 ft (1.2 m) of cover.

9.11.9.3 The engineering design of buried pipe in navigable waters shall evaluate, and where necessary implement additional cover to minimize the possibility of damage due to anchor drop or drag and ship grounding events.

Chapter 10 Instrumentation and Electrical Services

10.1 Scope. This chapter covers the requirements for instrumentation, controls, and electrical requirements for the LNG facility.

10.2 Liquid Level Gauging.

10.2.1 LNG Containers.

10.2.1.1 LNG containers shall be equipped with two independent liquid level gauging devices that compensate for variations in liquid density.

10.2.1.2 Gauging devices shall be designed and installed so that they can be replaced without taking the container out of operation.

10.2.1.3 Each container shall be provided with two independent high-liquid-level alarms, which shall be permitted to be part of the liquid level gauging devices.

(A) The alarm shall be set so that the operator can stop the flow without exceeding the maximum permitted filling height and shall be located so that they are audible to personnel controlling the filling.

(B) The high-liquid-level flow cutoff device required in 10.2.1.4 shall not be considered as a substitute for the alarm.

10.2.1.4 The LNG container shall be equipped with a high-liquid-level flow cutoff device, which shall be separate from all gauges.

10.2.2 Tanks for Refrigerants or Flammable Process Fluids.

10.2.2.1 Each storage tank shall be equipped with a liquid level gauging device.

10.2.2.2 If it is possible to overfill the tank, a high-liquid-level alarm shall be provided in accordance with 10.2.1.3.

10.2.2.3 The requirements of 10.2.1.4 shall apply to installations of flammable refrigerants.

10.3 Pressure Gauging. Each container shall be equipped with a pressure gauge connected to the container at a point above the maximum intended liquid level.

10.4 Vacuum Gauging. Vacuum-jacketed equipment shall be equipped with instruments or connections for checking the absolute pressure in the annular space.

10.5 Temperature Indicators. Temperature-monitoring devices shall be provided in field-erected containers to assist in controlling temperatures when the container is placed into service or as a method of checking and calibrating liquid level gauges.

10.5.1 Vaporizers shall be provided with indicators to monitor inlet and outlet temperatures of LNG, vaporized gas, and heating-medium fluids to ensure effectiveness of the heat transfer surface.

10.5.2 Temperature-monitoring systems shall be provided where foundations supporting cryogenic containers and equipment could be affected adversely by freezing or frost heaving of the ground.

10.6 Emergency Shutdown. Instrumentation for liquefaction, storage, and vaporization facilities shall be designed so that, in the event that power or instrument air failure occurs, the system will proceed to a fail-safe condition that is maintained until the operators can take action either to reactivate or to secure the system.

10.7 Electrical Equipment.

10.7.1 Electrical equipment and wiring shall be in accordance with *NFPA 70* or CSA C22.1, *Canadian Electrical Code*.

10.7.2* Fixed electrical equipment and wiring installed within the classified areas specified in Table 10.7.2 shall comply with Table 10.7.2 and Figure 10.7.2(a) through Figure 10.7.2(f) and shall be installed in accordance with *NFPA 70* .

10.7.3 Electrically classified areas shall be as specified in Table 10.7.2.

(A) The extent of the electrically classified area shall not extend beyond an unpierced wall, roof, or solid vaportight partition.

(B) The extent of the electrically classified areas shall be measured in accordance with Table 10.7.2.

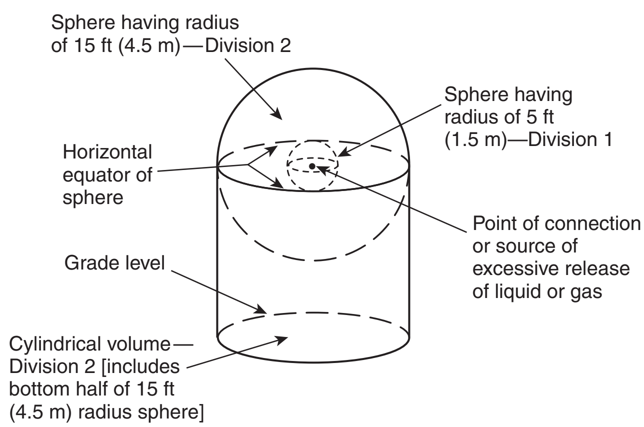


FIGURE 10.7.2(a) Extent of Classified Area Around Containers.

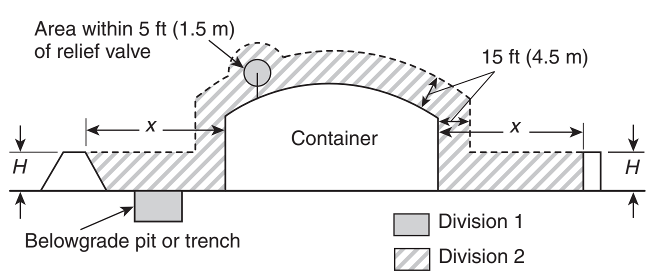


FIGURE 10.7.2(b) Dike Height Less Than Distance from Container to Dike ($H < x$).

Table 10.7.2 Electrical Area Classification

Part	Location	Group D, Division[a]	Extent of Classified Area
A	**LNG storage containers with vacuum breakers**		
	Inside containers	2	Entire container interior
B	**LNG storage container area**		
	Indoors	1	Entire room
	Outdoor aboveground containers (other than small containers)[b]	1	Open area between a high-type dike and the container wall where dike wall height exceeds distance between dike and container walls *[see Figure 10.7.2(c)]*
		2	Within 15 ft (4.5 m) in all directions from container walls and roof plus area inside a low-type diked or impounding area up to the height of the dike impoundment wall *[see Figure 10.7.2(b)]*
	Outdoor belowground containers	1	Within any open space between container walls and surrounding grade or dike *[seeFigure 10.7.2(d).]*
		2	Within 15 ft (4.5 m) in all directions from roof and sides *[see Figure 10.7.2(d).]*
C	**Nonfired LNG process areas containing pumps, compressors, heat exchangers, pipelines, connections, small containers, and so forth**		
	Indoors with adequate ventilation[c]	2	Entire room and any adjacent room not separated by a gastight partition and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver
	Outdoors in open air at or above grade	2	Within 15 ft (4.5 m) in all directions from this equipment and within the cylindrical volume between the horizontal equator of the sphere and grade *[See Figure 10.7.2(a).]*
D	**Pits, trenches, or sumps located in or adjacent to Division 1 or 2 areas**	1	Entire pit, trench, or sump
		2	Within 15 ft (4.5 m) in all directions, above grade *[see Figure 10.7.2(a)]*
E	**Discharge from relief valves**	1	Within 5 ft (1.5 m) in all directions from point of discharge
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from point of discharge
F	**Operational bleeds, drips, vents, or drains**		
	Indoors with adequate ventilation[c]	1	Within 5 ft (1.5 m) in all directions from point of discharge
		2	Beyond 5 ft (1.5 m) and entire room and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver
	Outdoors in open air at or above grade	1	Within 5 ft (1.5 m) in all directions from point of discharge
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from point of discharge
G	**Tank car, tank vehicle, and container loading and unloading**		
	Indoors with adequate ventilation[c]	1	Within 5 ft (1.5 m) in all directions from connections regularly made or disconnected for product transfer
		2	Beyond 5 ft (1.5 m) and entire room and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver

(continues)

Table 10.7.2 *Continued*

Part	Location	Group D, Division[a]	Extent of Classified Area
	Outdoors in open air at or above grade	1	Within 5 ft (1.5 m) in all directions from connections regularly made or disconnected for product transfer
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from a point where connections are regularly made or disconnected and within the cylindrical volume between the horizontal equator of the sphere and grade *[see Figure 10.7.2(a)]*
H	**Electrical seals and vents specified in 10.7.5 through 10.7.7**	2	Within 15 ft (4.5 m) in all directions from the equipment and within the cylindrical volume between the horizontal equator of the sphere and grade
I	**Marine terminal unloading areas** *[see Figure 10.7.2(f).]*	2	Within 15 ft (4.5 m) in all directions, above the deck, from the open sump

[a]See Article 500 in *NFPA 70* for definitions of classes, groups, and divisions. Article 505 can be used as an alternate to Article 500 for classification of hazardous areas using an equivalent zone classification to the division classifications specified in Table 10.7.2. Most of the flammable vapors and gases found within the facilities covered by NFPA 59A are classified as Group D. Ethylene is classified as Group C. Much of the available electrical equipment for hazardous locations is suitable for both groups.
[b]Small containers are portable and of less than 200 gal (760 L) capacity.
[c]Ventilation is considered adequate where provided in accordance with the provisions of this standard.

10.7.4 When electrical equipment is installed with enclosures residing in electrically classified areas per 10.7.2, the enclosures either shall be rated for that area classification or shall be in accordance with NFPA 496.

10.7.5 The interior of an LNG container shall not be a classified area where the following conditions are met:

(1) Electrical equipment is de-energized and locked out until the container is purged of air.
(2) Electrical equipment is de-energized and locked out prior to allowing air into the container.
(3) The electrical system is designed and operated to de-energize the equipment automatically when the pressure in the container is reduced to atmospheric pressure.

10.7.6 Each interface between a flammable fluid system and an electrical conduit or wiring system, including process instrumentation connections, integral valve operators, foundation heating coils, canned pumps, and blowers, shall be sealed or isolated to prevent the passage of flammable fluids to another portion of the electrical installation.

10.7.6.1 Each seal, barrier, or other means used to comply with 10.7.6 shall be designed to prevent the passage of flammable fluids through the conduit, stranded conductors, and cables.

10.7.6.2 A primary seal shall be provided between the flammable fluid system and the electrical conduit wiring system.

(A) If the failure of the primary seal allows the passage of flammable fluids to another portion of the conduit or wiring system, an additional approved seal, barrier, or other means shall be provided to prevent the passage of the flammable fluid beyond the additional device or means if the primary seal fails.

(B) Each primary seal shall be designed to withstand the service conditions to which it can be exposed.

(C) Each additional seal or barrier and interconnecting enclosure shall be designed to meet the pressure and temperature requirements of the condition to which it could be exposed in the event of failure of the primary seal unless other approved means are provided to accomplish the purpose.

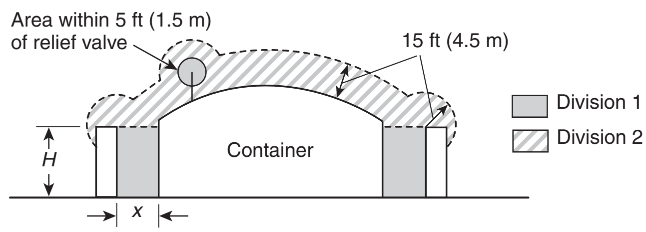


FIGURE 10.7.2(c) Dike Height Greater Than Distance from Container to Dike ($H > x$).

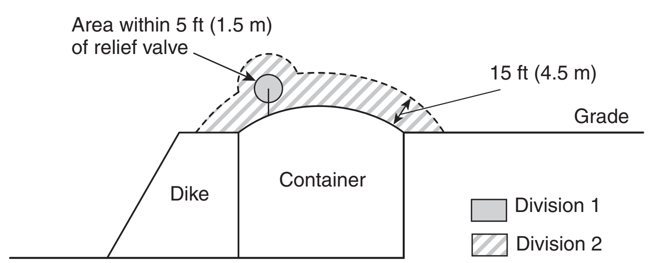


FIGURE 10.7.2(d) Container with Liquid Level Below Grade or Below Top of Dike.

10.7.6.3 Secondary Seal.

(A) Where secondary seals are used, the space between the primary and secondary seals shall be continuously vented to the atmosphere.

(B) Similar provisions to 10.7.6.3(A) shall be made on double-integrity primary sealant systems of the type used for submerged motor pumps.

(C) The requirements of 10.7.6.3(A) shall apply to double-integrity primary sealant systems.

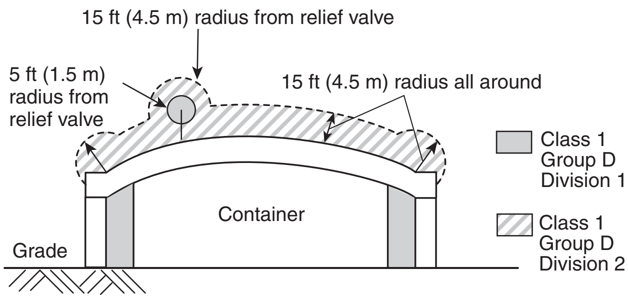


FIGURE 10.7.2(e) Full and Membrane Containment Tank Systems.

10.7.6.4 The seals specified in 10.7.6 and 10.7.7 shall not be used to meet the conduit sealing requirements of *NFPA 70* or CSA C22.1.

10.7.7 Where primary seals are installed, drains, vents, or other devices shall be provided to detect flammable fluids and leakage.

10.7.8 The venting of a conduit system shall minimize the possibility of damage to personnel and equipment if a flammable gas–air mixture is ignited.

10.8 Electrical Grounding and Bonding.

10.8.1* General. Electrical grounding and bonding shall be provided.

10.8.2 Static protection shall not be required where tank cars, tank vehicles, or marine equipment are loaded or unloaded and where both halves of metallic hose couplings or pipe are in contact.

10.8.3* If stray currents can be present or if impressed currents are used on loading and unloading systems (such as for cathodic protection), protective measures to prevent ignition shall be taken.

10.8.4* Lightning protection ground rods shall be provided for tanks supported on nonconductive foundations.

Chapter 11 Transfer Systems for LNG, Refrigerants, and Other Flammable Fluids

11.1 Scope. This chapter applies to the design, construction, and installation of systems involved in the transfer of LNG, refrigerants, flammable liquids, and flammable gases between storage containers or tanks and points of receipt or shipment by pipeline, tank car, tank vehicle, or marine vessel.

11.2 General Requirements.

11.2.1 Loading and unloading areas shall be posted with signs that read “No Smoking.”

11.2.2 Where multiple products are loaded or unloaded at the same location, loading arms, hoses, or manifolds shall be identified or marked to indicate the product or products to be handled by each system.

11.2.3 Purging of systems described in Section 11.1, when necessary for operations or maintenance, shall meet the requirements in 14.5.5.

11.3 Piping System.

11.3.1 Isolation valves shall be installed at the extremity of each transfer system.

11.4 Pump and Compressor Control.

11.4.1 In addition to a locally mounted device for shutdown of the pump or compressor drive, a readily accessible, remotely located device shall be provided a minimum of 25 ft (7.6 m)

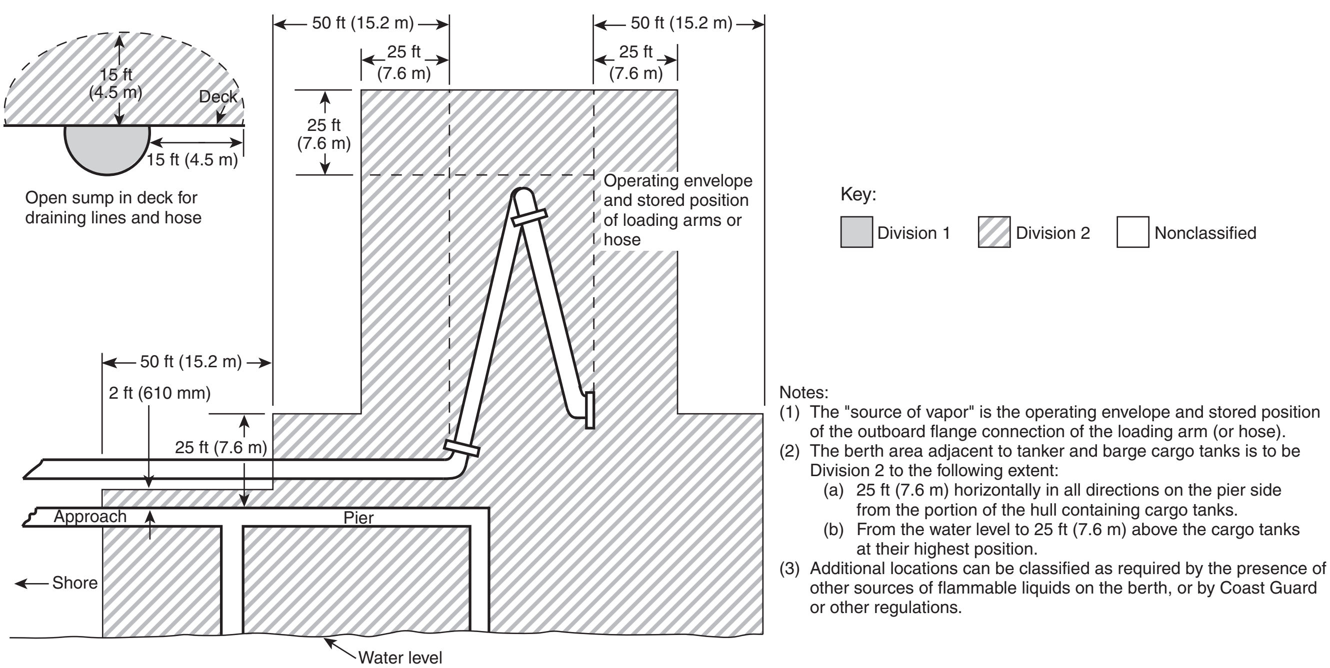


FIGURE 10.7.2(f) Classification of a Marine Terminal Handling LNG.

away from the equipment to shut down the pump or compressor in an emergency.

11.4.2 Remotely located pumps and compressors used for loading or unloading tank cars, tank vehicles, or marine vessels shall be provided with controls to stop their operation that are located at the loading or unloading area and at the pump or compressor site.

11.4.3 Controls located aboard a marine vessel shall be considered to be in compliance with 11.4.2.

11.4.4 Signal lights shall be provided at the loading or unloading area to indicate whether a remotely located pump or compressor used for loading or unloading is idle or in operation.

11.5 Marine Shipping and Receiving.

11.5.1 Berth Design Requirements.

11.5.1.1 The design of piers, docks, wharves, and jetties shall incorporate the following:

(1) Wave characteristics
(2) Wind characteristics
(3) Prevailing currents
(4) Tidal ranges
(5) Water depth at the berth and in the approach channel
(6) Maximum allowable absorbed energy during berthing and maximum face pressure on the fenders
(7) Arrangement of breasting dolphins
(8) Vessel approach velocity
(9) Vessel approach angle
(10) Minimum tug requirements, including horsepower
(11) Safe working envelope of the loading/unloading arms
(12) Arrangement of mooring dolphins

11.5.2 Piping (or Pipelines).

11.5.2.1 Pipelines shall be located on the dock or pier so that they are not exposed to damage from vehicular traffic or other possible causes of physical damage.

11.5.2.2 Underwater pipelines shall be located or protected so that they are not exposed to damage from marine traffic, and their location shall be posted or identified.

11.5.2.3 Isolation valving and bleed connections shall be provided at the loading or unloading manifold for both liquid and vapor return lines so that hoses and arms can be blocked off, drained or pumped out, and depressurized before disconnecting.

(A) Liquid isolation valves, regardless of size, and vapor valves 8 in. (200 mm) and larger shall be equipped with powered operators in addition to a means for manual operation.

(B) Power-operated valves shall be capable of being closed both locally and from a remote control station located at least 50 ft (15 m) from the manifold area.

(C) Unless the valve automatically fails closed on loss of power, the valve actuator and its power supply within 50 ft (15 m) of the valve shall be protected against operational failure due to a fire exposure of at least a 10-minute duration.

(D) Valves shall be located at the point of hose or arm connection to the manifold.

(E) Bleeds or vents shall discharge to a safe area.

11.5.2.4 In addition to the isolation valves at the manifold, each vapor return and liquid transfer line shall have a readily accessible isolation valve located on shore near the approach to the waterway, dock, or pier.

(A) Where more than one line is involved, the valves shall be grouped in one location.

(B) Valves shall be identified for their service.

(C) Valves 8 in. (200 mm) and larger shall be equipped with powered operators.

(D) Means for manual operation shall be provided.

11.5.2.5 Pipelines used only for liquid unloading shall be provided with a check valve located at the manifold adjacent to the manifold isolation valve.

11.5.2.6 Marine terminals used for loading ships or barges shall be equipped with a vapor return line designed to connect to the vessel's vapor return connections.

11.5.3* Emergency Shutdown System. Each marine LNG transfer system shall have an emergency shutdown (ESD) system that does the following:

(1) Can be activated manually
(2) Provides a system for a coordinated safe shutdown of all relevant LNG transfer components on the vessel, at the berth, and within the LNG plant

11.6 Tank Vehicle and Tank Car Loading and Unloading Facilities.

11.6.1 Transfer shall be made only into tank cars approved for the service.

11.6.2 Tank vehicles not under the jurisdiction of the DOT shall comply with the following standards:

(1) LNG tank vehicles shall comply with CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*.
(2) LP-Gas tank vehicles shall comply with NFPA 58.
(3) Flammable liquid tank vehicles shall comply with NFPA 385.

11.6.3 A rack structure, if provided, shall be constructed of a noncombustible material.

11.6.4 A tank vehicle loading and unloading area shall be of sufficient size to accommodate the vehicles without excessive movement or turning of the vehicles.

11.6.5 Transfer piping, pumps, and compressors shall be located or protected by barriers so that they are protected from damage by rail or vehicle movements.

11.6.6 Isolation valves and bleed connections shall be provided at the loading or unloading manifold for both liquid and vapor return lines so that hoses and arms can be blocked off, drained of liquid, and depressurized before disconnecting.

11.6.7 Bleeds or vents shall discharge to a safe area.

11.6.8 In addition to the isolation valving at the manifold, an emergency shutdown valve shall be provided in each liquid and vapor line at least 25 ft (7.6 m) but not more than 100 ft (30 m) from each loading or unloading area.

11.6.8.1 Emergency valves shall be readily accessible for emergency use.

11.6.8.2 Where a common line serves multiple loading or unloading areas, only one emergency valve shall be required.

11.6.8.3 Where the loading or unloading area is closer than 25 ft (7.6 m) to the sending or receiving container, a valve that can be operated remotely from a point 25 ft to 100 ft (7.6 m to 30 m) from the area shall be installed.

11.6.9 Pipelines used only for liquid unloading shall have a check valve at the manifold adjacent to the manifold isolation valve.

11.7 Pipeline Shipping and Receiving.

11.7.1 Isolation valves shall be installed at all points where transfer systems connect into pipeline systems.

11.7.2 The pipeline system shall be designed so that it cannot exceed its temperature or pressure limits.

11.7.3 Where multiple products are loaded or unloaded at the same location, loading arms, hoses, and manifolds shall be identified or marked to indicate the product or products to be handled by each system.

11.7.4 Bleed or vent connections shall be provided so that loading arms and hoses can be drained and depressurized prior to disconnecting.

11.7.5 If vented to a safe location, gas or liquid shall be permitted to be vented to the atmosphere to assist in transferring the contents of one container to another.

11.8 Hoses and Arms.

11.8.1 Hoses or arms used for transfer shall be designed for the temperature and pressure conditions of the loading or unloading system.

11.8.2 Hoses shall be approved for the service and shall be designed for a bursting pressure of at least five times the working pressure.

11.8.3 Flexible metallic hose or pipe and swivel joints shall be used where operating temperatures can be below −60°F (−51°C).

11.8.4 Loading arms used for marine loading or unloading shall have alarms to indicate that the arms are approaching the limits of their extension envelopes.

11.8.5 Counterweights shall be selected to operate with ice formation on uninsulated hoses or arms.

11.8.6 Hoses shall be tested at least annually to the maximum pump pressure or relief valve setting and shall be inspected visually before each use for damage or defects.

11.8.7 Marine loading or unloading operations shall be periodically tested as required by the authority having jurisdiction.

11.9 Communications and Lighting.

11.9.1 Communications shall be provided at loading and unloading locations to allow the operator to be in contact with other personnel associated with the loading or unloading operation.

11.9.2 Facilities transferring LNG during hours of darkness shall have lighting at the transfer area.

11.9.3 The LNG marine transfer area for LNG shall have a ship-to-shore communication system and a separate emergency ship-to-shore communication system.

11.9.4 The communication system required in 11.9.3 shall be continuously monitored both aboard ship and at the terminal.

Chapter 12 Fire Protection, Safety, and Security

12.1 Scope.

12.1.1 This chapter covers equipment and procedures designed to minimize the consequences from released LNG, flammable refrigerants, flammable liquids, and flammable gases in facilities constructed and arranged in accordance with this standard.

12.1.2 The provisions in Chapter 12 augment the leak and spill control provisions in other chapters.

12.1.3 This chapter includes basic plant security provisions.

12.2* General. Fire protection shall be provided for all LNG facilities.

12.2.1* The extent of such protection shall be determined by an evaluation based on fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property.

12.2.1.1* Protection installed as a result of the evaluation in 12.2.2 shall be designed, engineered, installed and tested based upon fire protection equipment standards incorporated by reference adhering to the following standards:

(1) NFPA 10, *Standard for Portable Fire Extinguishers*
(2) NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*
(3) NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*
(4) NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*
(5) NFPA 13, *Standard for the Installation of Sprinkler Systems*
(6) NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*
(7) NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*
(8) NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*
(9) NFPA 17, *Standard for Dry Chemical Extinguishing Systems*
(10) NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*
(11) NFPA 22, *Standard for Water Tanks for Private Fire Protection*
(12) NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*
(13) *NFPA 72* , *National Fire Alarm and Signaling Code*
(14) NFPA *101* , *Life Safety Code*
(15) NFPA 750, *Standard on Water Mist Fire Protection Systems*
(16) NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems*
(17) NFPA 1901, *Standard for Automotive Fire Apparatus*
(18) NFPA 1961, *Standard on Fire Hose*
(19) NFPA 1962, *Standard for the Care, Use, Inspection, Service Testing, and Replacement of Fire Hose, Couplings, Nozzles, and Fire Hose Appliances*
(20) NFPA 1963, *Standard for Fire Hose Connections*
(21) NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*

12.2.2* The evaluation shall determine the following:

(1) The type, quantity, and location of equipment necessary for the detection and control of fires, leaks, and spills of LNG, flammable refrigerants, or flammable gases
(2) The type, quantity, and location of equipment necessary for the detection and control of potential nonprocess and electrical fires
(3) The methods necessary for protection of the equipment and structures from the effects of fire exposure
(4) Requirements for fire protection water systems
(5)* Requirements for fire-extinguishing and other fire control equipment
(6) The equipment and processes to be incorporated within the emergency shutdown (ESD) system, including analysis of subsystems, if any, and the need for depressurizing specific vessels or equipment during a fire emergency
(7) The type and location of sensors necessary to initiate automatic operation of the ESD system or its subsystems
(8) The availability and duties of individual plant personnel and the availability of external response personnel during an emergency
(9)* The personal protective equipment, special training, and qualification needed by individual plant personnel for their respective emergency duties as specified by NFPA 600
(10) Requirements for other fire protection equipment and systems

12.3 Emergency Shutdown (ESD) Systems.

12.3.1 Each LNG facility shall have an ESD system(s) to isolate or shut off a source of LNG, flammable liquids, flammable refrigerant, or flammable gases, and to shut down equipment whose continued operation could add to or sustain an emergency.

12.3.2 Valves, control systems, and equipment required by the ESD system shall not be required to duplicate valves, control systems, and equipment installed to meet other requirements of the standard where multiple functions are incorporated in the valves, control systems, and equipment. The valves, control systems, and equipment shall meet the requirements for ESD systems.

12.3.3 If equipment shutdown will introduce a hazard or result in mechanical damage to equipment, the shutdown of any equipment or its auxiliaries shall be omitted from the ESD system if the effects of the continued release of flammable or combustible fluids are controlled.

12.3.4 The ESD system(s) shall be of a fail-safe design or shall be otherwise installed, located, or protected to minimize the possibility that it will become inoperative in the event of an emergency or a failure at the normal control system.

12.3.5 ESD systems that are not of a fail-safe design shall have all components that are located within 50 ft (15 m) of the equipment controlled in either of the following ways:

(1) Installed or located where they cannot be exposed to a fire
(2) Protected against failure due to a fire exposure of at least 10 minutes duration

12.3.6 Operating instructions identifying the location and operation of emergency controls shall be posted in the facility area.

12.3.7 Manual actuators shall be located in an area accessible in an emergency, shall be at least 50 ft (15 m) from the equipment they serve, and shall be marked with their designated function.

12.4 Gas, Fire, and Leak Detection.

12.4.1 Areas, including enclosed buildings, that can have the presence of flammable gas, LNG or flammable refrigerant spills, and fire shall be monitored as required by the evaluation in 12.2.1.

12.4.2 Gas Detection.

12.4.2.1 Continuously monitored flammable gas detection systems shall sound an alarm at the plant site and at a constantly attended location if the plant site is not attended continuously.

12.4.2.2 Flammable gas detection systems shall activate an audible and a visual alarm at not more than 25 percent of the lower flammable limit of the gas or vapor being monitored.

12.4.3 Fire Detectors.

12.4.3.1 Fire detectors shall activate an audible and a visual alarm at the plant site and at a constantly attended location if the plant site is not attended continuously.

12.4.3.2 If so determined by an evaluation in accordance with 12.2.1, fire detectors shall be permitted to activate portions of the ESD system.

12.4.4 Leak Detection. Leak detection shall activate an audible and visual alarm at the plant site and at a constantly attended location if the plant is not continuously attended.

12.4.5* The detection systems shall be designed, installed, and maintained in accordance with *NFPA 72* .

12.5 Fire Protection Water Systems.

12.5.1 A water supply and a system for distributing and applying water shall be provided for protection of exposures; for cooling containers, equipment, and piping; and for controlling unignited leaks and spills, unless an evaluation in accordance with 12.2.1 determines that the use of water is unnecessary or impractical.

12.5.2 The fire water supply and distribution systems, if provided, shall simultaneously supply water to fixed fire protection systems, including monitor nozzles, at their design flow and pressure, involved in the maximum single incident expected in the plant plus an allowance of 1000 gpm (63 L/sec) for hand hose streams for at least 2 hours.

12.5.3 Where provided, fire protection water systems shall be designed in accordance with NFPA 13, NFPA 14, NFPA 15, NFPA 20, NFPA 22, NFPA 24, NFPA 750, or NFPA 1961 as applicable.

12.6 Fire Extinguishing and Other Fire Control Equipment.

12.6.1* Portable or wheeled fire extinguishers shall be recommended for gas fires by their manufacturer.

12.6.1.1 Portable or wheeled fire extinguishers shall be available at strategic locations, as determined in accordance with 12.2.1, within an LNG facility and on tank vehicles.

12.6.1.2 Portable and wheeled fire extinguishers shall conform to the requirements of NFPA 10.

12.6.1.3 Handheld portable dry chemical extinguishers shall contain minimum nominal agent capacities of 20 lb (9 kg) or greater and shall have a minimum 1 lb/sec (0.45 kg/sec) agent discharge rate.

12.6.1.4 For LNG plant hazard areas where minimal Class A fire hazards are present, the selection of potassium bicarbonate–based dry chemical extinguishers is recommended.

12.6.1.5 Wheeled portable dry chemical extinguishers shall contain minimum nominal agent capacities of 125 lb (56.7 kg) or greater and shall have a minimum 2 lb/sec (0.90 kg/sec) agent discharge rate.

12.6.2 If provided, automotive and trailer-mounted fire apparatus shall not be used for any other purpose.

12.6.3 Fire trucks shall conform to NFPA 1901.

12.6.4 Automotive vehicles assigned to the plant shall be provided with a minimum of one portable dry chemical extinguisher having a capacity of not less than 18 lb (8.2 kg).

12.7 Maintenance of Fire Protection Equipment. Plant operators shall prepare and implement a maintenance program for all plant fire protection equipment.

12.8 Personnel Safety.

12.8.1* Protective clothing that will provide protection against the effects of exposure to LNG shall be available and readily accessible at the LNG plant.

12.8.2* Employees who are involved in emergency response activities beyond the incipient stage shall be equipped with protective clothing and equipment and trained in accordance with NFPA 600.

12.8.3* Written practices and procedures shall be developed to protect employees from the hazards of entry into confined or hazardous spaces.

12.8.4* At least three portable flammable gas indicators shall be readily available.

12.9 Security.

12.9.1 Security Assessment.

12.9.1.1* A security assessment covering hazards, threats, vulnerabilities, and consequences shall be prepared for the LNG plant.

12.9.1.2 The security assessment shall be available to the authority having jurisdiction on a nonpublic basis.

12.9.2 The LNG plant operator shall provide a security system with controlled access that is designed to prevent entry by unauthorized persons.

12.9.3 At LNG plants, there shall be a protective enclosure, including a peripheral fence, building wall, or natural barrier enclosing major facility components such as the following:

(1) LNG storage containers
(2) Flammable refrigerant storage tanks
(3) Flammable liquid storage tanks
(4) Other hazardous materials storage areas
(5) Outdoor process equipment areas
(6) Buildings housing process or control equipment
(7) Onshore loading and unloading facilities

12.9.3.1 The LNG plant shall be secured either by a single continuous enclosure or by multiple independent enclosures or approved barrier(s).

12.9.3.2 Where the enclosed area exceeds 1250 ft^2 (116 m^2), at least two exit gates or doors shall be provided.

12.9.4 LNG plants shall be illuminated in the vicinity of protective enclosures and in other areas as necessary to promote security of the LNG plant.

Chapter 13 Requirements for Stationary Applications Using ASME Containers

13.1 Scope.

13.1.1 This chapter provides requirements for the installation, design, fabrication, and siting of LNG facilities using containers of 100,000 U.S. gal (379 m^3) water capacity and less, constructed in accordance with the ASME *Boiler and Pressure Vessel Code.*

13.1.2 The maximum aggregate storage capacity of the facility shall be 280,000 U.S. gal (1060 m^3) water capacity.

13.2 General Requirements.

13.2.1 Site preparation shall include provisions for retention of spilled LNG within the limits of plant property and for surface water drainage.

13.2.2 All-weather accessibility to the site for emergency services equipment shall be provided.

13.2.3 Storage and transfer equipment at unattended facilities shall be secured to prevent tampering.

13.2.4 Operating instructions identifying the location and operation of emergency controls shall be posted conspicuously in the facility area.

13.2.5 Designers, fabricators, and constructors of LNG facility systems and equipment shall be competent in their respective fields.

13.2.6 Supervision shall be provided for the fabrication, construction, and acceptance tests of facility components necessary to ensure that facilities are in compliance with this standard.

13.2.7 Facilities transferring LNG during the night shall have lighting at the transfer area.

13.2.8 The maximum allowable working pressure shall be specified for all pressure-containing components.

13.3 Containers.

13.3.1 All piping that is a part of an LNG container, including piping between the inner and outer containers, shall be in accordance with either Section VIII of the ASME *Boiler and Pressure Vessel Code*, or ASME B 31.3, *Process Piping.*

13.3.2 Compliance with 13.3.1 shall be stated on or appended to the ASME *Boiler and Pressure Vessel Code*, Appendix W, Form U-1, "Manufacturer's Data Report for Pressure Vessels."

13.3.3 Internal piping between the inner tank and the outer tank and within the insulation space shall be designed for the maximum allowable working pressure of the inner tank, with allowance for thermal stresses.

13.3.4 Bellows shall not be permitted within the insulation space.

13.3.5 Containers shall be double-walled, with the inner tank holding LNG surrounded by insulation contained within the outer tank.

13.3.6 The inner tank shall be of welded construction and in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, and shall be ASME-stamped and registered with the National Board of Boiler and Pressure Vessel Inspectors or another agency that registers pressure vessels.

13.3.7 The inner tank supports shall be designed for shipping, seismic, and operating loads.

13.3.8 The support system to accommodate the expansion and contraction of the inner tank shall be designed so that the resulting stresses imparted to the inner and outer tanks are within allowable limits.

13.3.9 The outer tank shall be of welded construction using any of the following materials:

(1) Any of the carbon steels in Section VIII, Part UCS of the ASME *Boiler and Pressure Vessel Code* at temperatures at or above the minimum allowable use temperature in Table 1A of the ASME *Boiler and Pressure Vessel Code*, Section II, Part D
(2) Materials with a melting point below 2000°F (1093°C) where the container is buried or mounded

13.3.10 Where vacuum insulation is used, the outer tank shall be designed by either of the following:

(1) The ASME *Boiler and Pressure Vessel Code*, Section VIII, Parts UG-28, UG-29, UG-30, and UG-33, using an external pressure of not less than 15 psi (103 kPa)
(2) Paragraph 3.6.2 of CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*

13.3.11 Heads and spherical outer tanks that are formed in segments and assembled by welding shall be designed in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Parts UG-28, UG-29, UG-30, and UG-33, using an external pressure of 15 psi (103 kPa).

13.3.12 The outer tank shall be equipped with a relief device or other device to release internal pressure.

13.3.12.1 The discharge area shall be at least 0.00024 in.^{2}/lb (0.34 mm^2/kg) of the water capacity of the inner tank, but the area shall not exceed 300 in.^{2} (0.2 m^2).

13.3.12.2 The relief device shall function at a pressure not exceeding the internal design pressure of the outer tank, the external design pressure of the inner tank, or 25 psi (172 kPa), whichever is least.

13.3.13 Thermal barriers shall be provided to prevent the outer tank from falling below its design temperature.

13.3.14 Seismic Design.

13.3.14.1 Shop-built containers designed and constructed in accordance with the ASME *Boiler and Pressure Vessel Code* and their support systems shall be designed for the dynamic forces associated with horizontal and vertical accelerations as follows:
For horizontal force:

[13.3.14.1a]

$$V = Z_c \times W$$

For vertical force:

[13.3.14.1b]

$$P = \frac{2}{3} Z_c \times W$$

where:
Z_c = seismic coefficient equal to 0.60 S_{DS} where S_{DS} is the maximum design spectral acceleration determined in accordance with the provisions of ASCE 7, *Minimum Design Loads for Buildings and Other Structures*, using an importance factor, *I*, of 1.0 for the site class most representative of the subsurface conditions where the LNG facility is located
W = total weight of the container and its contents

13.3.14.2 Usage.

(A) The method of design described in 13.3.14.1 shall be used only where the natural period, *T*, of the shop-built container and its supporting system is less than 0.06 second.

(B) If the natural period *T* is 0.06 or greater, 7.4.4.1 and 7.4.4.2 shall apply.

13.3.14.3 The container and its supports shall be designed for the resultant seismic forces in combination with the operating loads, using the allowable stresses increase shown in the code or standard used to design the container or its supports.

13.3.14.4 The requirements of Section 13.3 shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

13.3.15 Each container shall be identified by the attachment of a nameplate(s) in an accessible location marked with the information required by the ASME *Boiler and Pressure Vessel Code* and the following:

(1) Builder's name and date container was built
(2) Nominal liquid capacity
(3) Design pressure at the top of the container
(4) Maximum permitted liquid density
(5) Maximum filling level
(6) Minimum design temperature

13.3.16 All penetrations of storage containers shall be marked with the function of the penetration. Penetration markings shall be visible if frosting occurs.

13.4 Container Filling. Containers designed to operate at a pressure in excess of 15 psi (103 kPa) shall be equipped with a device(s) that prevents the container from becoming liquid-full or the inlet of the relief device(s) from becoming covered with liquid when the pressure in the container reaches the set pressure of the relieving device(s) under all conditions.

13.5 Container Foundations and Supports.

13.5.1 LNG container foundations shall be designed and constructed in accordance with *NFPA 5000* .

13.5.2 The design of saddles and legs shall include shipping loads, erection loads, wind loads, and thermal loads.

13.5.3 Foundations and supports shall have a fire resistance rating of not less than 2 hours and shall be resistant to dislodgment by hose streams.

Table 13.6.2.1 Distances from Containers and Exposures

Container Water Capacity		Minimum Distance from Edge of Impoundment or Container Drainage System to Offsite Buildings and Property Lines That Can Be Built Upon		Minimum Distance Between Storage Containers	
gal	m³	ft	m	ft	m
1000–2000	3.8–7.6	15	4.6	5	1.5
2001–18,000	≥7.6–68.1	25	7.6	5	1.5
18,001–30,000	≥68.1–114	50	15	5	1.5
30,001–70,000	≥114–265	75	23	¼ of the sum of the diameters of adjacent containers [5 ft (1.5 m) minimum]	
>70,000	>265	0.7 times the container diameter [100 ft (30 m) minimum]			

13.5.4 LNG storage containers installed in an area subject to flooding shall be secured to prevent the release of LNG or flotation of the container in the event of a flood.

13.6 Container Installation.

13.6.1 LNG containers of 1000 gal (3.8 m^3) and smaller shall be located as follows:

(1) 125 gal (0.47 m^3) or less, 0 ft (0 m) from property lines that can be built upon
(2) Larger than 125 gal (0.47 m^3) to 1000 gal (3.8 m^3), 10 ft (3.0 m) from property lines that can be built upon

13.6.2 Minimum Distance.

13.6.2.1 The minimum distance from the edge of an impoundment or container drainage system serving aboveground and mounded containers larger than 1000 gal (3.8 m^3) shall be in accordance with Table 13.6.2.1 for each of the following:

(1) Nearest offsite building
(2) The property line that can be built upon
(3) Spacing between containers

13.6.2.2 The distance from the edge of an impoundment or container drainage system to buildings or walls of concrete or masonry construction shall be reduced from the distance in Table 13.6.2.1 with the approval of the authority having jurisdiction with a minimum of 10 ft (3 m).

13.6.3 Underground LNG tanks shall be installed in accordance with Table 13.6.3.

13.6.4 Buried and underground containers shall be provided with means to prevent the 32°F (0°C) isotherm from penetrating the soil.

13.6.5 Where heating systems are used, they shall be installed such that any heating element or temperature sensor used for control can be replaced.

13.6.6* All buried or mounded components in contact with the soil shall be constructed from material resistant to soil corrosion or protected to minimize corrosion.

13.6.7 A clear space of at least 3 ft (0.9 m) shall be provided for access to all isolation valves serving multiple containers.

13.6.8 LNG containers of greater than 125 gal (0.5 m^3) capacity shall not be located in buildings.

13.6.9 The point where connections are made for product transfer shall be located not less than 25 ft (7.6 m) from the following:

(1) The nearest important building not associated with the LNG facility
(2) The line of adjoining property that can be built upon

13.6.10 LNG tanks and their associated equipment shall not be located where exposed to failure of overhead electric power lines operating at over 600 volts.

13.7 Automatic Product Retention Valves.

13.7.1 All liquid and vapor connections, except relief valve and instrument connections, shall be equipped with automatic fail-safe product retention valves.

Table 13.6.3 Distances from Underground Containers and Exposures

Container Water Capacity		Minimum Distance from Buildings and the Adjoining Property Line That Can Be Built Upon		Distance Between Containers	
gal	m³	ft	m	ft	m
<18,000	<68.1	15	4.6	15	4.6
18,000–30,000	68.1–114	25	7.6	15	4.6
30,001–100,000	>114	40	12.2	15	4.6

13.7.2* Automatic fail-safe product retention valves shall be designed to close on the occurrence of any of the following conditions:

(1) Fire detection or exposure
(2) Uncontrolled flow of LNG from the container
(3) Manual operation from a local and remote location

13.7.3 Connections used only for flow into the container shall be equipped with either two backflow valves, in series, or an automatic fail-safe product retention valve.

13.7.4 Appurtenances shall be installed as close to the container as practical so that a break resulting from external strain shall occur on the piping side of the appurtenance while maintaining intact the valve and piping on the container side of the appurtenance.

13.8 LNG Spill Containment.

13.8.1 Impoundment (dikes), topography, or other methods to direct LNG spills to a safe location and to prevent LNG spills from entering water drains, sewers, waterways, or any closed-top channel shall be used.

13.8.2 Flammable liquid storage tanks shall not be located within an LNG container impoundment area.

13.8.3 Impounding areas serving aboveground and mounded LNG containers shall have a minimum volumetric holding capacity, including any useful holding capacity of the drainage area and with allowance made for the displacement of snow accumulation, other containers, and equipment, in accordance with the following:

(1) Where containers in the dike area are constructed or protected to prevent failure from spilled LNG and fire in the dike, the minimum holding of the dike shall be the volume of the largest container in the dike.
(2) Where containers in the dike area are not constructed or protected to prevent failure from spilled LNG and fire in the dike, the minimum holding of the dike shall be equal to the total volume of the containers in the dike area.

13.8.4 Impounding areas shall be designed or equipped to clear rain or other water.

13.8.4.1 Where automatically controlled sump pumps are used, they shall be equipped with an automatic cutoff device that prevents their operation when exposed to LNG temperatures.

13.8.4.2 Piping, valves, and fittings whose failure could allow liquid to escape from the impounding area shall be designed to withstand continuous exposure to the temperature of LNG.

13.8.4.3 Where gravity drainage is employed for water removal, the gravity draining system shall be designed to prevent the escape of LNG by way of the drainage system.

13.9 Inspection.

13.9.1 Prior to initial operation, containers shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of this chapter.

13.9.2 Inspectors shall be qualified in accordance with the code or standard applicable to the container and as specified in this standard.

13.10 Shop Testing of LNG Containers.

13.10.1 The outer tank shall be leak tested.

13.10.2 Piping between the inner container and the first connection outside the outer container shall be tested in accordance with ASME B 31.3.

13.11 Shipment of LNG Containers. Containers shall be shipped under a minimum internal pressure of 10 psi (69 kPa) inert gas.

13.12 Field Testing of LNG Containers.

13.12.1 Containers and associated piping shall be leak tested prior to filling with LNG.

13.12.2 After acceptance tests are completed, there shall be no field welding on the LNG containers.

13.13 Welding on Containers.

13.13.1 Field welding shall be done only on saddle plates or brackets provided for the purpose.

13.13.2 Where repairs or modifications incorporating welding are required, they shall comply with the code or standard under which the container was fabricated.

13.13.3 Retesting by a method appropriate to the repair or modification shall be required only where the repair or modification is of such a nature that a retest actually tests the element affected and is necessary to demonstrate the adequacy of the repair or modification.

13.14 Piping.

13.14.1 All piping that is part of an LNG container and the facility associated with the container for handling cryogenic liquid or flammable fluid shall be in accordance with ASME B 31.3, and the following:

(1) Type F piping, spiral welded piping, and furnace butt-welded steel products shall not be permitted.
(2) All welding or brazing shall be performed by personnel qualified to the requirements of the ASME B 31.3, subsection 328.2, Welding Qualifications, and ASME *Boiler and Pressure Vessel Code*, Section IX, as applicable.
(3) Oxygen–fuel gas welding shall not be permitted.
(4) Brazing filler metal shall have a melting point exceeding 1000°F (538°C).
(5) All piping and tubing shall be austenitic stainless steel for all services below −20°F (−29°C).
(6) All piping and piping components, except gaskets, seals, and packing, shall have a minimum melting point of 1500°F (816°C).
(7) Aluminum shall be used only downstream of a product retention valve in vaporizer service.
(8) Compression-type couplings used where they can be subjected to temperatures below −20°F (−29°C) shall meet the requirements of ASME B 31.3, Section 315.
(9) Stab-in branch connections shall not be permitted.
(10) Extended bonnet valves shall be used for all cryogenic liquid service, and they shall be installed so that the bonnet is at an angle of not more than 45 degrees from the upright vertical position.

13.14.2* The level of examination of piping shall be specified.

13.15 Container Instrumentation.

13.15.1 General. Instrumentation for LNG facilities shall be designed so that, in the event of power or instrument air failure, the system will go into a fail-safe condition that can be maintained until the operators can take action to reactivate or secure the system.

13.15.2 Level Gauging. LNG containers shall be equipped with liquid level devices as follows:

(1) Containers of 1000 gal (3.8 m^3) or larger shall be equipped with two independent liquid level devices.
(2) Containers smaller than 1000 gal (3.8 m^3) shall be equipped with either a fixed length dip tube or other level devices.
(3) Containers of 1000 gal (3.8 m^3) or larger shall have one liquid level device that provides a continuous level indication ranging from full to empty and that is maintainable or replaceable without taking the container out of service.

13.15.3 Pressure Gauging and Control.

13.15.3.1 Each container shall be equipped with a pressure gauge connected to the container at a point above the maximum liquid level that has a permanent mark indicating the maximum allowable working pressure (MAWP) of the container.

13.15.3.2 Vacuum-jacketed equipment shall be equipped with instruments or connections for checking the pressure in the annular space.

13.15.3.3 Safety relief valves shall be sized to include conditions resulting from operational upset, vapor displacement, and flash vaporization resulting from pump recirculation and fire.

13.15.4 Pressure relief valves shall communicate directly with the atmosphere.

13.15.5 Pressure relief valves shall be sized in accordance with 7.3.6.5 or with CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Compressed Gas Storage Containers*.

13.15.6 Inner container pressure relief valves shall have a manual full-opening stop valve to isolate it from the container.

13.15.6.1 The stop valve shall be lockable or sealable in the fully open position.

13.15.6.2 The installation of pressure relief valves shall allow each relief valve to be isolated individually for testing or maintenance while maintaining the full relief capacities determined in 7.3.6.5.

13.15.6.3 Where only one pressure relief valve is required, either a full-port opening three-way valve used under the pressure relief valve and its required spare or individual valves beneath each pressure relief valve shall be installed.

13.15.7 Stop valves under individual safety relief valves shall be locked or sealed when opened and shall not be opened or closed except by an authorized person.

13.15.8 Safety relief valve discharge stacks or vents shall be designed and installed to prevent an accumulation of water, ice, snow, or other foreign matter and, if arranged to discharge directly into the atmosphere, shall discharge vertically upward.

13.16 Fire Protection and Safety. The requirements of Sections 12.1 and 12.2; 12.3.1; 12.4.1; Sections 12.5, 12.6, and 12.7; 12.8.2; and 12.8.3 shall apply.

13.17 Gas Detection. A portable flammable gas indicator shall be readily available.

13.18 Operations and Maintenance. Each facility shall have written operating, maintenance, and training procedures based on experience, knowledge of similar facilities, and conditions under which the facility will be operated.

13.18.1 Basic Operations Requirements. Each LNG facility shall meet the following requirements:

(1) Have written procedures covering operation, maintenance, and training
(2) Keep up-to-date drawings of LNG facility equipment showing all revisions made after installation
(3) Revise the plans and procedures as operating conditions or facility equipment require
(4) Establish a written emergency plan
(5) Establish liaison with appropriate local authorities such as police, fire department, or municipal works and inform them of the emergency plans and their role in emergency situations
(6) Analyze and document all safety-related malfunctions and incidents for the purpose of determining their causes and preventing the possibility of recurrence

13.18.2 Operating Procedures Manual.

13.18.2.1 Each facility shall have a written manual of operating procedures, including the following:

(1) Conducting a proper startup and shutdown of all components of the facility, including those for an initial startup of the LNG facility that will ensure that all components will operate satisfactorily
(2) Purging and inerting components
(3) Cooling down components
(4) Ensuring that each control system is properly adjusted to operate within its design limits
(5) Maintaining the vaporization rate, temperature, and pressure so that the resultant gas is within the design tolerance of the vaporizer and the downstream piping
(6) Determining the existence of any abnormal conditions and indicating the response to those conditions
(7) Ensuring the safety of personnel and property while repairs are carried out, whether or not equipment is in operation
(8) Ensuring the safe transfer of hazardous fluids
(9) Ensuring security at the LNG plant
(10) Monitoring operation by watching or listening for warning alarms from an attended control center and by conducting inspections on a planned, periodic basis
(11) Monitoring the foundation heating system weekly

13.18.2.2 The manual shall be accessible to operating and maintenance personnel.

13.18.2.3 The manual shall be updated when changes in equipment or procedures are made.

13.18.2.4 The operations manual shall contain procedures to ensure the following:

(1) That the cooldown of each system of components under its control and subjected to cryogenic temperatures is limited to a rate and a distribution pattern that maintain

the thermal stresses within the design limits of the system during the cooldown period, having regard for the performance of expansion and contraction devices

(2) That each facility has procedures to check each cryogenic piping system under its control during and after cooldown stabilization for leaks in areas where there are flanges, valves, and seals

13.18.2.5 Each operations manual shall include purging procedures that, when implemented, minimize the presence of a combustible mixture in LNG facility piping or equipment when a system is being placed into or taken out of operation.

13.18.2.6 The operations manual shall contain procedures for loading or unloading operations applicable to all transfers, including the following:

(1) Written procedures shall cover all transfer operations and shall cover emergency as well as normal operating procedures.
(2) Written procedures shall be kept up-to-date and available to all personnel engaged in transfer operations.
(3) Prior to transfer, gauge readings shall be obtained or inventory established to ensure that the receiving vessel cannot be overfilled.
(4) Levels of the receiving vessel shall be checked during transfer operations.
(5) The transfer system shall be checked prior to use to ensure that valves are in the correct position.
(6) Pressure and temperature conditions shall be observed during the transfer operation.

13.18.2.7 Each operations manual for a facility that transfers LNG from or to a cargo tank vehicle or a tank car shall contain procedures for loading or unloading tank cars or tank vehicles, including the following:

(1) While tank car or tank vehicle loading or unloading operations are in progress, rail and vehicle traffic shall be prohibited within 25 ft (7.6 m) of LNG facilities or within 50 ft (15 m) of refrigerants whose vapors are heavier than air.
(2) Prior to connecting a tank car, the car shall be checked and the brakes set, the derailer or switch properly positioned, and warning signs or lights placed as required.
(3) The warning signs or lights shall not be removed or reset until the transfer is completed and the car disconnected.
(4) Unless required for transfer operations, truck vehicle engines shall be shut off.
(5) Brakes shall be set and wheels checked prior to connecting for unloading or loading.
(6) The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.
(7) Prior to loading LNG into a tank car or tank vehicle that is not in exclusive LNG service, a test shall be made to determine the oxygen content in the container.
(8) If a tank car or tank vehicle in exclusive LNG service does not contain a positive pressure, it shall be tested for oxygen content.
(9) If the oxygen content in either case exceeds 2 percent by volume, the container shall not be loaded until it has been purged to below 2 percent oxygen by volume.

13.18.3 Emergency Procedures.

13.18.3.1 Each LNG facility shall have a written manual of emergency procedures that shall include the types of emergencies that are anticipated from an operating malfunction, structural collapse of part of the LNG facility, personnel error, forces of nature, and activities carried on adjacent to the LNG facility, including the following:

(1) Procedures for responding to controllable emergencies, including notification of personnel and the use of equipment that is appropriate for handling the emergency and the shutdown or isolation of various portions of the equipment and other applicable steps to ensure that the escape of gas or liquid is promptly cut off or reduced as much as possible
(2) Procedures for recognizing an uncontrollable emergency and for taking action to ensure that harm to the personnel at the LNG facility and to the public is minimized
(3) Procedures for the prompt notification of the emergency to the appropriate local officials, including the possible need to evacuate persons from the vicinity of the LNG plant
(4) Procedures for coordinating with local officials in the preparation of an emergency evacuation plan that sets forth the steps necessary to protect the public in the event of an emergency

13.18.3.2* When local officials are contacted in an emergency, procedures shall include the method of notification of the following:

(1) The quantity and location of fire equipment throughout the LNG plant
(2) Potential hazards at the LNG plant
(3) Communication and emergency control capabilities of the LNG plant
(4) The status of each emergency

13.18.4 Maintenance. Each facility shall have written maintenance procedures based on experience, knowledge of similar facilities, and conditions under which the facilities will be maintained.

13.18.4.1 Each LNG facility operator shall carry out periodic inspection, tests, or both on a schedule that is included in the maintenance plan on identified components and its support system in service in the LNG facility, to verify that the components are maintained in accordance with the equipment manufacturer's recommendations and the following:

(1) The support system or foundation of each component shall be inspected at least annually to ensure that the support system or foundation is sound.
(2) Each emergency power source at the LNG plant shall be tested monthly to ensure that it is operational and tested annually to ensure that it is capable of performing at its intended operating capacity.
(3) When a safety device serving a single component is taken out of service for maintenance or repair, the component shall also be taken out of service, except where the safety function is provided by an alternative means.
(4) Where the operation of a component that is taken out of service could cause a hazardous condition, a tag bearing the words "Do Not Operate," or equivalent, shall be attached to the controls of the component, or the component shall be locked out.
(5) Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open and shall be operated only by an authorized person.
(6) No more than one pressure or vacuum relief valve stop valve shall be closed at one time on an LNG container.

13.18.4.2 Maintenance Manual.

(A) Each facility operator shall prepare a written manual that sets out an inspection and maintenance program for identified components that are used in the facility.

(B) The maintenance manual for facility components shall include the following:

(1) The manner of carrying out and the frequency of the inspections and tests referred to in 13.18.4.1
(2) A description of any other action in addition to those referred to in 13.18.4.2(B)(1) that is necessary to maintain the facility in accordance with this standard
(3) All procedures to be followed during repairs on a component that is operating while it is being repaired, to ensure the safety of persons and property at the facility

(C) Each facility operator shall conduct the facility's maintenance program in accordance with the written manual for facility components.

13.18.4.3 Facility Maintenance.

(A) Each facility operator shall keep the grounds of the facility free from rubbish, debris, and other materials that could present a fire hazard.

(B) Each facility operator shall ensure that the components of the facility are kept free from ice and other foreign materials that could impede their performance.

(C) Each facility operator shall maintain the grassed area of its facility so that it does not create a fire hazard.

(D) All fire-control access routes within an LNG facility shall be maintained and kept unobstructed in all weather conditions.

13.18.4.4 Repairs that are carried out on components of a facility shall be carried out in a manner that ensures the following:

(1) That the integrity of the components is maintained in accordance with this standard
(2) That the components will operate in a safe manner
(3) That the safety of personnel and property during a repair activity is maintained

13.18.4.5 Each facility operator shall ensure that a control system that is out of service for 30 days or more is tested prior to its return to service, to ensure that it is in proper working order.

(A) Each facility operator shall ensure that the inspections and tests in this section are carried out at the intervals specified.

(B) Control systems that are used seasonally shall be inspected and tested before use each season.

(C) Control systems that are used as part of the fire protection system at the LNG plant shall be inspected and tested in accordance with the applicable fire codes and standards and conform to the following criteria:

(1) Monitoring equipment shall be maintained in accordance with *NFPA 72* and NFPA 1221.
(2) Fire protection water systems, if required, shall be maintained in accordance with NFPA 13, NFPA 14, NFPA 15, NFPA 20, NFPA 22, NFPA 24, and NFPA 25.
(3) Portable or wheeled fire extinguishers suitable for gas fires, preferably of the dry-chemical type, shall be available at strategic locations, as determined in accordance with Chapter 12, within an LNG facility and on tank vehicles and shall be maintained in accordance with NFPA 10.
(4) Fixed fire extinguishers and other fire-control systems that are installed shall be maintained in accordance with NFPA 11, NFPA 12, NFPA 12A, NFPA 16, and NFPA 17.

(D) Relief valves shall be inspected and set-point tested at least once every 2 calendar years, with intervals not exceeding 30 months, to ensure that each valve relieves at the proper setting.

(E) The external surfaces of LNG storage tanks shall be inspected and tested as set out in the maintenance manual for the following:

(1) Inner tank leakage
(2) Soundness of insulation
(3) Tank foundation heating to ensure that the structural integrity or safety of the tanks is not affected

(F) LNG storage facilities and, in particular, the storage container and its foundation shall be externally inspected after each major meteorological disturbance to ensure that the structural integrity of the LNG facility is intact.

13.18.4.6 Maintenance Records.

(A) Each facility operator shall maintain a record of the date and the type of each maintenance activity performed.

(B) Maintenance records shall be retained for a period of not less than 5 years.

13.18.5 Training.

13.18.5.1 Every facility operator shall develop, implement, and maintain a written training plan to instruct appropriate facility personnel with respect to the following:

(1) Carrying out the emergency procedures that relate to their duties at the facility as set out in the procedure manual referred to in 13.18.3, and providing first aid
(2) For permanent maintenance, operating, and supervisory personnel the following:
    (a) The basic operations carried out at the facility
    (b) The characteristics and potential hazards of LNG and other hazardous fluids involved in operating and maintaining the facility, including the serious danger from frostbite that can result from contact with LNG or cold refrigerants
    (c) The methods of carrying out their duties of maintaining and operating the facility as set out in the manual of operating and maintenance procedures referred to in 13.18.2 and 13.18.4
    (d) The LNG transfer procedures required in 13.18.2.6 and 13.18.2.7
    (e) Fire prevention, including familiarization with the fire control plan of the facility, fire fighting, the potential causes of fire in a facility, and the types, sizes, and likely consequences of a fire at a facility
    (f) Recognition of situations in which it is necessary to obtain assistance in order to maintain the security of the facility

13.18.5.2 Each LNG plant operator shall develop, implement, and maintain a written plan to keep the personnel at the LNG plant up to date on the function of the systems, fire prevention, and security at the LNG facility.

13.18.5.3 The plans required in 13.18.5.2 shall provide for training sessions to update personnel at intervals that do not exceed 2 years.

13.18.5.4 Employee Records.

(A) Every facility operator shall maintain a record for each applicable employee of the facility that sets out the training given to the employee under 13.18.5.

(B) The employee records shall be maintained for at least 2 years after the date that the employee ceases to be employed at the facility.

13.18.5.5 Each facility operator shall ensure the following:

(1) That facility personnel receive applicable training referred to in 13.18.5
(2) That facility personnel have experience related to their assigned duties

13.18.5.6 Any person who has not completed the training or who does not have the experience set out in 13.18.5 shall be under the control of trained personnel.

Chapter 14 Operating, Maintenance, and Personnel Training

14.1* Scope. This chapter contains basic requirements and minimum standards for the safety aspects of the operation and maintenance of LNG plants.

14.2 General Requirements.

14.2.1 Each operating company shall develop documented operating, maintenance, and training procedures, based on experience and conditions under which the LNG facility is operated.

14.2.2 The operating company shall meet the following requirements:

(1) Document procedures covering operation, maintenance, and training
(2) Maintain up-to-date drawings, charts, and records of LNG facility equipment
(3) Revise plans and procedures when operating conditions or LNG facility equipment are revised
(4) Ensure cooldown of components in accordance with 14.3.5
(5) Establish a documented emergency plan
(6) Establish liaisons with local authorities such as police, fire department, or municipal works to inform them of the emergency plans and their roles in emergency situations
(7)* Analyze and document all safety-related conditions for the purpose of determining their causes and preventing the possibility of recurrence

14.3 Manual of Operating Procedures.

14.3.1 All LNG facility components shall be operated in accordance with the operating procedures manual.

14.3.2 The operating procedures manual shall be accessible to all LNG facility personnel and shall be kept readily available in the operating control center.

14.3.3 The operating manual shall be updated when there are changes in equipment or procedures.

14.3.4 The operating manual shall include procedures for the startup and shutdown of all components of the LNG facility, including those for initial startup of the LNG facility, to ensure that all components operate satisfactorily.

14.3.5 The operating manual shall include procedures for purging components, making components inert, and cooldown of components.

14.3.5.1 Procedures shall ensure that the cooldown of each system of components that is under the operating company's control, and that is subjected to cryogenic temperatures, is limited to a rate and distribution pattern that maintains the thermal stresses within the design limits of the system during the cooldown period regarding the performance of expansion and contraction devices.

14.3.6 The operating manual shall include procedures to ensure that each control system is adjusted to operate the process within its design limits.

14.3.7 The operating manual of LNG plants with liquefaction facilities shall include procedures to maintain the temperatures, levels, pressures, pressure differentials, and flow rates within their design limits for the following:

(1) Boilers
(2) Turbines and other prime movers
(3) Pumps, compressors, and expanders
(4) Purification and regeneration equipment
(5) Equipment in cold boxes

14.3.8 The operating manual shall include procedures for the following:

(1) Maintaining the vaporization rate, temperature, and pressure so that the resultant gas is within the design tolerance of the vaporizer and the downstream piping
(2) Determining the existence of any abnormal conditions and the response to those conditions in the LNG facility
(3) The safe transfer of LNG and hazardous fluids, including prevention of overfilling of containers
(4) Security

14.3.9 The operations manual shall include procedures for monitoring operations.

14.3.10 Written procedures shall be available to cover all transfer operations and shall cover emergency as well as normal operating procedures.

14.3.11 Written procedures shall be kept up to date and available to all personnel engaged in transfer operations.

14.4 Emergency Procedures.

14.4.1 Each operations manual shall contain emergency procedures.

14.4.2 The emergency procedures shall include, at a minimum, emergencies that are anticipated from an operating malfunction, structural collapse of part of the LNG facility, personnel error, forces of nature, and activities carried on adjacent to the plant.

14.4.3 The emergency procedures shall include but not be limited to procedures for responding to controllable emergencies, including the following:

(1) Notification of personnel
(2) Use of equipment appropriate for handling the emergency
(3) The shutdown or isolation of various portions of the equipment
(4) Other steps to ensure that the escape of gas or liquid is promptly cut off or reduced as much as possible

14.4.4 The emergency procedures shall include procedures for recognizing an uncontrollable emergency and for taking action to achieve the following:

(1) Minimizing harm to the personnel at the LNG plant and to the public
(2) Prompt notification of the emergency to the appropriate local officials, including the possible need to evacuate persons from the vicinity of the LNG plant

14.4.5 The emergency procedures shall include procedures for coordinating with local officials in the preparation of an emergency evacuation plan that sets forth the steps necessary to protect the public in the event of an emergency, including the following:

(1) Quantity and location of fire equipment throughout the LNG plant
(2) Potential hazards at the LNG plant
(3) Communication and emergency control capabilities at the LNG plant
(4) Status of each emergency

14.4.6 Emergency procedures shall include procedures for dealing with unignited gas releases.

14.4.7 Each facility that handles LNG shall develop a contingency plan to address potential incidents that can occur in or near the transfer area, including the following:

(1) A description of the fire equipment and systems and their operating procedures, including a plan showing the locations of all emergency equipment
(2) LNG release response procedures, including contact information for local response organizations
(3) Emergency procedures for unmooring a vessel, including the use of emergency towing wires (e.g., "fire warps")
(4) Tug requirements for emergency situations and for specific foreseeable incidents that are berth-specific
(5) Telephone numbers of authorities having jurisdiction, hospitals, fire departments, and other emergency response agencies

14.5 Monitoring Operations.

14.5.1* Control Center. Operations monitoring shall be carried out by an attended control center that watches or listens for warning alarms and by inspections conducted at least at the intervals set out in the written operating procedures referred to in Section 14.3 and, at a minimum, on a weekly basis.

14.5.2 LNG Tank Foundation.

14.5.2.1 Where the bottom of the outer tank is in contact with the soil, the heating system shall be monitored at least once a week to ensure that the 32°F (0°C) isotherm is not penetrating the soil.

14.5.2.2 Any settlement in excess of that anticipated in the design shall be investigated, and corrective action taken as required.

14.5.3 Cooldown. Each cryogenic piping system that is under the operating company's control shall be checked during and after cooldown stabilization for leaks in areas where there are flanges, valves, and seals.

14.5.4 Depressurizing. The discharge from depressurizing shall be directed to minimize exposure to personnel or equipment.

14.5.5 Purging.

14.5.5.1 The temperature of the purge gas or liquid shall be within the design temperature limits of the container or other equipment.

14.5.5.2 The pressure of the container or other equipment during purging shall be within the design pressure limits of the container.

14.5.5.3* Piping systems shall be purged of air or gas in a safe manner. *(See Section 9.8.)*

14.5.5.4* Container Purging, Drying, and Cooldown Procedures.

14.5.5.4.1 Taking an LNG container out of service shall not be regarded as a normal operation.

14.5.5.4.2 The activities of 14.5.5 shall require the preparation of detailed procedures.

14.5.5.4.3 Only experienced, trained personnel shall dry, purge, or cool down LNG containers.

14.5.5.4.4 Before an LNG container is put into service, the air shall be displaced by an inert gas, following a written purging procedure.

14.5.5.4.5* Before a container is taken out of service, the natural gas in the container shall be purged from the container with an inert gas, following a written purging procedure.

14.5.5.5 During purging operations, the oxygen content of the container or other equipment shall be monitored by the use of an oxygen analyzer.

14.6 Transfer of LNG and Flammables.

14.6.1 Where bulk transfers are made into stationary storage containers, the LNG being transferred shall be compatible in composition or in temperature and density with the LNG already in the container.

14.6.2 Where the composition or the temperature and density are not compatible, means shall be taken to prevent stratification and vapor evolution that could cause rollover.

14.6.3 Where a mixing nozzle or agitation system is provided, it shall be designed to prevent rollover.

14.6.4 At least one qualified person shall be in constant attendance while a transfer is in progress.

14.6.5 Sources of ignition shall not be permitted in loading or unloading areas while transfer is in progress.

14.6.6 Loading and Unloading Tank Vehicle and Tank Car.

14.6.6.1 Sources of ignition shall not be allowed in loading or unloading areas while transfer is in progress.

14.6.6.2 Loading and unloading areas shall be posted with signs that read "No Smoking."

14.6.6.3 Where multiple products are loaded or unloaded at the same location, loading arms, hoses, or manifolds shall be identified or marked to indicate the product or products to be handled by each system.

14.6.6.4 Prior to transfer, gauge readings shall be obtained or inventory established to ensure that the receiving container cannot be overfilled, and levels shall be checked during transfer operations.

14.6.6.5 The transfer system shall be checked prior to use to ensure that valves are in the correct position.

14.6.6.6 Transfer operations shall be commenced slowly and if any unusual variance in pressure or temperature occurs, transfer shall be stopped until the cause has been determined and corrected.

14.6.6.7 Pressure and temperature conditions shall be monitored during the transfer operation.

14.6.6.8 While tank car or tank vehicle loading or unloading operations are in progress, rail and vehicle traffic shall be prohibited within 25 ft (7.6 m) of LNG facilities or within 50 ft (15 m) of refrigerants whose vapors are heavier than air.

14.6.6.8.1 Before a tank car is connected, the car shall be checked and the brakes set, the derailer or switch properly positioned, and warning signs or lights placed as required.

14.6.6.8.2 The warning signs or lights shall not be removed or reset until the transfer is completed and the car disconnected.

14.6.6.8.3 Truck vehicle engines shall be shut off if they are not required for transfer operations.

14.6.6.8.4 Brakes shall be set and wheels chocked prior to connection for unloading or loading.

14.6.6.8.5 The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.

14.6.6.9 Oxygen Content.

(A) Before LNG is loaded into a tank car or tank vehicle that is not in exclusive LNG service, a test shall be made to determine the oxygen content in the container.

(B) If the oxygen content exceeds 2 percent by volume, the container shall not be loaded until it has been purged to below 2 percent oxygen by volume.

(C) If a tank car or tank vehicle in exclusive LNG service does not contain a positive pressure, it shall be tested for oxygen content.

14.6.6.10 Before loading or unloading, a tank vehicle shall be positioned so it can exit the area without backing up, when the transfer operation is complete.

14.6.6.11 Tank cars and tank vehicles that are top-loaded through an open dome shall be bonded electrically to the fill piping or grounded before the dome is opened.

14.6.6.12 Communications shall be provided at loading and unloading locations so that the operator can be in contact with other remotely located personnel who are associated with the loading or unloading operation.

14.6.7 Marine Shipping and Receiving.

14.6.7.1 Vessel Arrival.

14.6.7.1.1 The requirements of 14.4.7 shall be communicated to the vessel operator to facilitate safe vessel berthing and unberthing.

14.6.7.1.2 Warning signs or barricades shall be used to indicate that transfer operations are in progress.

14.6.7.1.3 A vessel-specific mooring plan utilizing the criteria developed in 11.5.1 shall be developed for each ship calling at the waterfront facility.

14.6.7.1.4 The vessel shall be moored in a safe and effective manner.

14.6.7.1.5 The terminal operator shall certify in writing that the provisions of 14.9.5.1 and 14.9.5.3 are met.

14.6.7.1.6 This certification shall be available for inspection at the waterfront facility that handles LNG.

14.6.7.2 Prior to Transfer.

14.6.7.2.1 Before transferring LNG, the facility shall do the following:

(1) Inspect the transfer piping and equipment to be used during the transfer and replace any worn or inoperable parts
(2) Note the pressure, temperature, and volume to ensure they are safe for transfer for each of the vessel's cargo tanks from which cargo will be transferred
(3) Review and agree with the vessel operator on the sequence of transfer operations
(4) Review and agree with the vessel operator on the transfer rate
(5) Review and agree with the vessel operator on the duties, location, and watches of each person assigned for transfer operations
(6) Review emergency procedures from the emergency manual
(7) Review and agree with the vessel operator on means (dedicated channels, etc.) of maintaining a direct communication link between the watches on the ship and shoreside throughout the cargo transfer
(8) Ensure that transfer connections allow the vessel to move to the limits of its moorings without exceeding the normal operating envelope of the loading arms
(9) Ensure that each part of the transfer system is aligned to allow the flow of LNG to the desired location
(10) Verify that the cargo liquid and vapor lines on the vessel, the loading arms, and the shoreside piping systems have been purged of oxygen
(11) Ensure that warning signs that warn that LNG is being transferred are displayed
(12) Verify that no source of ignition exists in the marine transfer area for LNG
(13) Ensure that personnel are on duty in accordance with the operations manual
(14) Test the sensing and alarm systems, the emergency shutdown system, and the communication systems to determine that they are operable

14.6.7.2.2 Prior to transfer, the officer in charge of vessel cargo transfer and the person in charge of the shore terminal shall inspect their respective facilities to ensure that transfer equipment is in operating condition.

14.6.7.2.3 Following the inspection described in 14.6.7.2.2, the officer in charge of vessel cargo transfer and the person in charge of the shore terminal shall meet and determine the transfer procedure, verify that ship-to-shore communications exist, and review emergency procedures.

14.6.7.2.4 After the pretransfer inspection required by 14.6.7.2.1 has been satisfactorily completed, there shall be no transfer of LNG until a declaration of inspection that demonstrates full compliance with 14.6.7.2.2 is executed and signed.

(A) One signed copy of the declaration of inspection shall be given to the person in charge of transfer operations on the vessel, and one signed copy shall be retained for 30 days after completion of the transfer at the waterfront facility that handles LNG.

(B) Each declaration of inspection shall contain the following:

(1) The name of the vessel and the waterfront facility that handles LNG
(2) The dates and times that transfer operations began and ended
(3) The signature of the person in charge of shoreside transfer operations and the date and time of signing, indicating that he or she is ready to begin transfer operations
(4) The signature of each relief person in charge and the date and time of each relief
(5) The signature of the person in charge of shoreside transfer operations and the date and time of signing, indicating that the marine transfer has been completed

14.6.7.2.5 The communication system required in 11.9.3 shall be continuously monitored both aboard ship and at the terminal.

14.6.7.3 Marine Connections.

14.6.7.3.1 When loading arms are connected for marine loading or unloading operations, all bolt holes in a flange shall be utilized for the connection.

14.6.7.3.2 Blind flanges shall be utilized on those arms not engaged in loading or unloading operations.

14.6.7.3.3 All connections shall be leaktight and tested prior to operation.

14.6.7.3.4 Marine loading or unloading arms shall be purged prior to use and purged and completely drained upon completion of transfer.

14.6.7.3.5 Marine loading or unloading operations shall be at atmospheric pressure when the arm(s) are connected or disconnected.

14.6.7.4* Transfer Operations in Progress.

14.6.7.4.1 Vehicle traffic shall be prohibited on the pier or dock within 100 ft (30 m) of the loading and unloading manifold while transfer operations are in progress.

14.6.7.4.2 Warning signs or barricades shall be used to indicate that transfer operations are in progress.

14.6.7.4.3* There shall be two independent means of egress, including emergency egress, from the ship.

14.6.7.4.4 During transfer of a ship's stores, including nitrogen, personnel involved in the transfer of a ship's stores shall not have simultaneous responsibility involved in the transfer of LNG.

14.6.7.4.5 Sources of ignition shall not be permitted in the marine transfer area while transfer is in progress.

14.6.7.4.6 General cargo, other than ships' stores for the LNG tank vessel, shall not be handled over a pier or dock within 100 ft (30 m) of the point where connections are made for LNG, and flammable fluids transfer while LNG or flammable fluids are being transferred through piping systems.

14.6.7.5 Bunkering Operations.

14.6.7.5.1 Bunkering operations shall be in accordance with any requirements established by the authority having jurisdiction over vessels or terminals.

14.6.7.5.2 During bunkering operations, the following shall apply:

(1) Personnel performing bunkering operations shall not have simultaneous responsibility for the transfer of LNG as cargo.
(2) No vessels shall be moored alongside the LNG vessel without the permission of the authority having jurisdiction.

14.7 Maintenance Manual.

14.7.1* Each operating company shall have a documented plan that sets out inspection and maintenance program requirements for each component used in its LNG facility that is identified as requiring inspection and maintenance.

14.7.2 Each maintenance program shall be conducted in accordance with its documented plan for LNG facility components identified in the plan as requiring inspection and maintenance.

14.7.3 Each operating company shall perform the periodic inspections, tests, or both, on a schedule that is included in the maintenance plan on identified components and its support system identified as requiring inspection and maintenance that is in service in its LNG facility.

14.7.4 The maintenance manual shall refer to maintenance procedures, including procedures for the safety of personnel and property while repairs are carried out, regardless of whether the equipment is in operation.

14.7.5 The maintenance manual shall include the following for LNG facility components:

(1) The manner of carrying out and the frequency of inspections and tests
(2) A description of any other action, in addition to those referred to in 14.7.5, that is necessary to maintain the LNG facility in accordance with this standard
(3) All procedures to be followed during repairs on a component that is operating while it is being repaired, to ensure the safety of persons and property at the LNG plant

14.7.6 Procedures for the inspection of all pipe-in-pipe components, including vacuum levels, shall be specified and demonstrated to be appropriate for the installed condition.

14.7.7 Procedures for the repair and maintenance of all pipe in pipe components, including vacuum levels, shall be specified and demonstrated to be appropriate for the installed condition.

14.8 Maintenance.

14.8.1* Each operating company shall ensure that components in its LNG facility that could accumulate combustible mixtures are purged after being taken out of service and before being returned to service.

14.8.2 Where the operation of a component that is taken out of service could cause a hazardous condition, a tag bearing the words "Do Not Operate," or the equivalent, shall be attached to the controls of the component, or the component shall be locked out.

14.8.3 Foundation.

14.8.3.1 The support system or foundation of each component shall be inspected at least annually.

14.8.3.2 If the foundation is found to be incapable of supporting the component, it shall be repaired.

14.8.4 Emergency Power. Each emergency power source at the LNG plant shall be tested monthly to ensure that it is operational. Annual testing of the emergency power source shall also be conducted to ensure that it is capable of performing at its documented intended capacity, taking into account the power required to start some and simultaneously operate other equipment that would be served by the power source in a plant emergency.

14.8.5 Insulation systems for impounding surfaces shall be inspected annually.

14.8.6 Hoses for LNG and refrigerant transfer shall be tested at least annually to the maximum pump pressure or relief valve setting and shall be inspected visually before each use for damage or defects.

14.8.7 Marine loading or unloading operations shall be periodically tested as required by the authority having jurisdiction.

14.8.8 Repairs. Repairs that are carried out on components of an LNG facility shall be carried out in a manner that ensures the following:

(1) That the integrity of the components is maintained, in accordance with this standard
(2) That components operate in a safe manner
(3) That the safety of personnel and property during a repair activity is maintained

14.8.9 Site Housekeeping. Each operating company shall do the following:

(1) Keep the grounds of its LNG plant free from rubbish, debris, and other materials that could present a fire hazard
(2) Ensure that the presence of foreign material contaminants or ice is avoided or controlled to maintain the operational safety of each LNG facility component
(3) Maintain the grassed area of its LNG plant so that it does not create a fire hazard.
(4) Ensure that fire control access routes within its LNG plant are unobstructed and reasonably maintained in all weather conditions

14.8.10 Control Systems, Inspection, and Testing.

14.8.10.1 Each operating company shall ensure that a control system that is out of service for 30 days or more is tested prior to returning it to service, to ensure that it is in proper working order.

14.8.10.2 Each operating company shall ensure that the inspections and tests in this section are carried out at the intervals specified.

14.8.10.3 Control systems that are used seasonally shall be inspected and tested before use each season.

14.8.10.4 Control systems that are used as part of the fire protection system at the LNG facility shall be inspected and tested in accordance with the applicable fire code and conform to the following:

(1) Monitoring equipment shall be maintained in accordance with *NFPA 72* and NFPA 1221.
(2) Fire protection water systems shall be maintained in accordance with NFPA 13, NFPA 14, NFPA 15, NFPA 20, NFPA 22, NFPA 24, NFPA 25, NFPA 750, and NFPA 1962.
(3)* Portable or wheeled fire extinguishers suitable for gas fires shall be available at strategic locations, as determined in accordance with Chapter 12, within an LNG facility and on tank vehicles and shall be maintained in accordance with NFPA 10.
(4) Fixed fire extinguishers and other fire control equipment shall be maintained in accordance with NFPA 11, NFPA 12, NFPA 12A, NFPA 16, NFPA 17, and NFPA 2001.

14.8.10.5 Control systems, other than those referred to in 14.8.10.3 and 14.8.10.4, shall be inspected and tested once each calendar year at intervals that do not exceed 15 months.

14.8.10.6 Stationary LNG tank relief valves shall be inspected and set-point tested at least once every 2 calendar years, with intervals not exceeding 30 months, to ensure that each valve relieves at the proper setting.

14.8.10.7 All other relief valves protecting hazardous fluid components shall be randomly inspected and set-point tested at intervals not exceeding 5 years plus 3 months.

14.8.10.8 Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open.

14.8.10.9* Stop valves shall not be operated except by an authorized person.

14.8.10.10 An LNG container shall have no more than one stop valve closed at one time.

14.8.10.11 When a component is served by a single safety device and the safety device is taken out of service for maintenance or repair, the component shall also be taken out of service, unless safety is accomplished by an alternative means.

14.8.11 LNG Storage Tanks. The external surfaces of LNG storage tanks shall be inspected and tested as set out in the maintenance manual for the following:

(1) Inner tank leakage
(2) Soundness of insulation
(3) Tank foundation heating, to ensure that the structural integrity or safety of the tanks is not affected

14.8.12 Meteorological and Geophysical Events.

14.8.12.1 LNG storage facilities and, in particular, the storage container and its foundation shall be externally inspected after each major meteorological disturbance to ensure that the structural integrity of the LNG facility is intact.

14.8.12.2 If a potentially damaging geophysical or meteorological event occurs, the following shall be accomplished:

(1) The plant shall be shut down as soon as is practical.
(2) The nature and extent of damage, if any, shall be determined.
(3) The plant shall not be restarted until operational safety is re-established.

14.8.13 Corrosion Control.

14.8.13.1 Each operating company shall ensure the following for metallic components of its LNG facility that could be adversely affected with respect to integrity or reliability by corrosion during their service life:

(1) Protection from corrosion in accordance with Section 9.10
(2) Inspection and replacement or repair under a program of scheduled maintenance in accordance with the manual referred to under Section 14.3

14.8.13.2 Each operating company shall ensure that each component of its LNG facilities that is subject to interference from an electrical current is protected so that the electrical interference is minimized.

14.8.13.3 Each impressed current power source shall be installed and maintained such that it does not interfere with any communication or control system at the LNG plant.

14.8.13.4* Every operating company shall monitor the corrosion control provided in accordance with Section 9.10.

14.8.13.5 Each buried or submerged component that is cathodically protected shall be surveyed at least once each calendar year at intervals that do not exceed 15 months, to ensure that the system meets the corrosion control requirements of applicable standards.

14.8.13.6 Each cathodic protection rectifier or impressed current system shall be inspected at least six times each calendar year at intervals that do not exceed 2½ months, to ensure that it is operating properly.

14.8.13.7 Interference bonds shall be inspected at least once each calendar year at intervals that do not exceed 15 months.

14.8.13.8 Each exposed component that is subject to corrosion from the atmosphere shall be inspected at intervals that do not exceed 3 years.

14.8.13.9* Components covered by insulation that are subject to external corrosion shall be periodically monitored based upon a written corrosion control program.

14.8.13.10 Where a component is protected from internal corrosion by a coating or inhibitors, monitoring devices designed to detect internal corrosion, such as coupons or probes, shall be located where corrosion is most likely to occur.

14.8.13.11 Internal corrosion control monitoring devices shall be checked at least two times each calendar year at intervals not exceeding 7½ months.

14.8.13.12 Components that will not be adversely affected by internal corrosion during the time that the component will be in use in LNG facilities shall be exempt from the requirements of 14.8.13.

14.8.13.13 If it is discovered by inspection or otherwise that corrosion is not being controlled at the LNG facilities, necessary actions to control or monitor the corrosion shall be taken.

14.9 Personnel Training.

14.9.1 Every operating plant shall have a written training plan to instruct all LNG plant personnel.

14.9.2 The training plan shall include training of permanent maintenance, operating, and supervisory personnel with respect to the following:

(1) The basic operations carried out at the LNG facility
(2) The characteristics and potential hazards of LNG and other hazardous fluids involved in operating and maintaining the LNG facility, including the serious danger from frostbite that can result from contact with LNG or cold refrigerants
(3) Methods of carrying out the duties of maintaining and operating the LNG facility as set out in the manual of operating and maintenance procedures referred to in Section14.3 and Section 14.7
(4) LNG transfer procedures
(5) Fire prevention, including familiarization with the fire control plan of the LNG plant, fire fighting, the potential causes of fire in an LNG plant, and the types, sizes, and likely consequences of a fire at an LNG plant
(6) Recognition of situations when it would be necessary to obtain assistance in order to maintain the security of the LNG plant

14.9.3 All LNG plant personnel shall meet the following requirements:

(1) LNG plant personnel shall receive the training referred to in 14.9.2.
(2) LNG plant personnel shall have experience related to their assigned duties.

14.9.4 Any person who has not completed the training or received experience set out in 14.9.2 shall be under the control of trained personnel.

14.9.5 Marine Transfer Training. All persons involved in the marine transfer of LNG shall be thoroughly familiar with all aspects of the transfer procedure, including potential hazards and emergency procedures.

14.9.5.1 Training for personnel involved in the marine transfer of LNG shall include the following:

(1) LNG transfer procedures, including practical training under the supervision of a person with such experience as determined by the terminal operator
(2) The provisions of the contingency plan required in 14.4.7

14.9.5.2 Time spent assisting in the transfer shall fulfill this practical training requirement.

14.9.5.3 Each person involved in the shoreside transfer operations shall have been trained in accordance with the requirements of 14.9.2 and shall have the following:

(1) At least 48 hours of LNG transfer experience
(2) Knowledge of the hazards of LNG

(3) Familiarity with the provisions of Chapter 11
(4) Knowledge of the procedures in the terminal's operations manual and emergency manual

14.9.6 Refresher Training.

14.9.6.1 Persons who are required to receive the training in 14.9.2 or 14.9.5 shall receive refresher training in the same subjects at least once every 2 years.

14.9.6.2 Performing actual loading or unloading operations, under the observation of a qualified individual, shall fulfill the requirement for refreshing of practical training in 14.9.5.

14.10 Records.

14.10.1 Each operating company shall maintain for a period of not less than 5 years a record of the date and type of each maintenance activity performed on each component of the LNG facility, including a record of the date that a component is taken out of or placed into service.

14.10.2 Records shall be made available during business hours upon reasonable notice.

14.10.3 For the life of the LNG facility, each LNG facility operator shall maintain records of each test, survey, or inspection required by this standard in detail sufficient to demonstrate the adequacy of corrosion control measures.

14.10.4 A record of all training shall be maintained for each employee of an LNG facility, and the records shall be maintained for at least 2 years after the date that the employee ceases to be employed at the LNG facility.

Chapter 15 Performance (Risk Assessment) Based LNG Plant Siting

15.1 Scope.

15.1.1 This chapter includes the calculation of risks to persons outside the boundary of a liquefied natural gas (LNG) plant, arising from potential releases of LNG and other hazardous substances stored, transferred, or handled in the plant.

15.1.2 Where approved, the requirements of this chapter shall be complied with, in LNG facility siting and layout analysis, as an alternative to the assessments required in Chapter 5 of this code.

15.1.3 The provisions of this chapter are applicable to newly proposed facilities and existing facilities where significant modifications and improvements are proposed. Only the modifications and improvements in existing facilities shall be subject to the requirements of this chapter.

15.1.4 The chapter does not include the assessment of risks from LNG or other hazardous materials associated with the plant arising from transportation caused releases outside the plant boundary.

15.2 General Requirements.

15.2.1 LNG plants shall be designed and located in such areas as to not pose intolerable risks to the surrounding populations, installations, or property.

15.2.2* The requirements of this chapter shall be used to assess the level of risks to surrounding population to ensure that the individual risk and the societal risk do not exceed tolerable levels in accordance with Section 15.9.

15.2.3 If the plant is modified or other conditions change, the plant risk may change. Therefore, reassessments of plant risk shall be undertaken at the earlier of:

(1) When conditions change as a direct consequence of actions and significant modifications undertaken by the plant
(2) Every 5 years
(3) As required by the authority having jurisdiction (AHJ)

15.3 Definitions. The following definitions shall apply only to usage in Chapter 15.

15.3.1* As Low as Reasonably Practicable (ALARP). The level of risk that represents the point, objectively assessed, at which the time, difficulty and cost of further reduction measures become unreasonably disproportionate to the additional risk reduction obtained.

15.3.2 Event. The combination of successive outcomes of LNG, flammable fluids, flammable refrigerants or toxic material release and its subsequent hazard to persons exposed.

15.3.3* Individual Risk. The frequency, expressed in number of realizations per year, at which an individual, with continuous potential exposure, may be expected to sustain a serious or fatal injury.

15.3.4 Societal Risk. The cumulative risk exposure by all persons sustaining serious or fatal injury from an event in the LNG plant.

15.4 Risk Calculations and Basis of Assessment.

15.4.1* Both individual risks and societal risk(s) values shall be evaluated in the area around the LNG plant by using quantitative risk analysis (QRA) protocol. The generally accepted QRA protocol, specified in any one of the following publications shall be used in assessing the risks:

(1) American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety (CCPS), "Guidelines for Chemical Process Quantitative Risk Analysis," 2000
(2) "Five Steps to Risk Assessment," INDC 163, rev. 1, Health and Safety Executive, 1998
(3) "Risk Criteria for Land-use Planning in the Vicinity of Major Industrial Hazards," HMSO, Health and Safety Executive, 1989
(4) "Risk Management–Risk Assessment Techniques," BSI EN 31010:2010, European Norm Standard
(5) TNO, "Guidelines for Quantitative Risk Assessment, RIVM, The Purple Book," Netherlands, 2005

15.4.2* The selected QRA procedure shall be approved by the AHJ.

15.4.3 Individual risks shall be presented in the form of contours of constant individual risk values. Societal risk shall be presented in the form of a diagram of cumulative annual frequency of casualty exceedance vs. the number of exposed population subject to the casualty (i.e., the F-N plot). Uncertainty values in the calculation of the risks (both frequency and casualty) shall be included in the diagram.

15.4.4 Risks calculated shall be compared with values of risks to which the population in the general vicinity of the proposed/existing plant may be subject due to natural causes or from other human activities.

15.5 LNG and Other Hazardous Materials Release Scenarios.

15.5.1 Catalog of Scenarios of Release. A spectrum of LNG and other hazardous material release scenarios from transfer piping, storage tank(s), vaporizer(s) and other vulnerable equipment in the plant shall be developed through the use of process hazard analyses (PHAs), HAZOP, or other thorough, systematic hazard-identification studies and scenario evaluations acceptable to the AHJ. In addition, the spectrum of releases shall include those identified as design spills in 5.3.3.7. Credible large-release scenarios that may pose risks outside the property line shall also be included along with their occurrence probabilities.

15.5.2 Release Specifications.

15.5.2.1 The release rates and durations (and when necessary the total release quantity) of LNG and other hazardous material releases shall be calculated for the scenarios of release identified in 15.5.1.

15.5.2.2 The calculation of the rate of release shall document the following:

(1) The hole or puncture sizes and upstream conditions consistent with the different storage conditions and appurtenances considered in the release scenarios identified in Section 15.5.1.
(2) The thermodynamic condition, including the pressure and temperature, of the fluid upstream of the release point

15.5.2.3 The thermal and physical characteristics of the substrate exposed to a release shall be considered in analyzing the subsequent behavior of the fluid released.

15.5.2.4 The spectrum of hazardous behavior of the released fluid due to its interaction with the substrate, the environment, and natural tendencies shall be considered and documented. These behavior modes that shall be considered include, but not limited to, flashing, aerosol formation, liquid jetting, pool formation and flow, dispersion of vapors, jet fires, flash fires, explosions, fireballs, pool fires, BLEVES, and liquid water interaction effects.

15.6 Release Probabilities and Conditional Probabilities.

15.6.1* The annual probability of LNG and other hazardous material releases from various equipment, for scenarios identified in 15.4.1 and 15.4.2, shall be based on Table 15.6.1.

15.6.2 Site-specific modifications to the probability values in Table 15.6.1 shall be considered and, if used in subsequent analysis, shall be approved.

15.6.3 The conditional probability for each type of hazardous behavior, identified pursuant to the requirements in 15.5.2.4, shall be obtained from the AHJ approved conditional probability databases.

15.6.4 The details of values of probabilities used in the calculations and the sources of data shall be documented.

15.7 Environmental Conditions and Occurrence Probabilities.

15.7.1 Site specific statistics on the environmental conditions shall be gathered either by direct measurements at the site for periods of time acceptable to obtain statistically meaningful data or from the nearest meteorological station.

15.7.2 The frequency of occurrence of different weather and other environmental parameters with conditional probabilities of occurrence of 25 percent, 50 percent, 75 percent and 99 percent shall be documented and considered in hazard calculations. These environmental parameters shall include wind speed, wind direction, atmospheric temperature, atmospheric relative humidity, and ground/water substrate temperature (if available).

15.7.3 Topographic and structural features in the vicinity of the proposed plant site that impact on the consequence of the released fluid shall be considered in the assessment of hazards. These features include, but are not limited to, liquid momentum for dike overtopping assessment, aerodynamic roughness of the site and surrounding area for dispersion behavior of vapors, and congestion due to plants, shrubs, and trees and its effect on potential vapor explosions.

Table 15.6.1 Example Component Failure Database

Component	Annual Probability of Failure
Atmospheric cryogenic tanks	
(1) Instantaneous failure of primary container and outer shell, release of entire contents (single containment tank)	5E-07
(2) Instantaneous failure of primary container and outer shell, release of entire contents (double containment tank)	1.25E-08
(3) Instantaneous failure of primary and secondary container, release of entire contents (full and membrane containment tanks)	1E-08
Pressurized storage (Containers) — instantaneous release of entire contents	5E-07
Pressure relief valves — outflow at the maximum rate	2E-05
Process equipment	
(1) Pumps — catastrophic failure	1E-04
(2) Compressors with gasket — catastrophic failure	1E-04
(3) Heat exchanger — instantaneous release of entire contents from plate heat exchanger	5E-05
Transfer equipment — rupture of loading/unloading arm	3E-08
Piping — aboveground	**Annual probability of failure per meter**
(1) Rupture for nominal diameter <3 in. (75 mm)	1E-06
(2) Rupture for nominal diameter from 3 in. (75 mm)up to and including 6 in. (150 mm)	3E-07
(3) Rupture for nominal diameter >6 in. (150) mm	1E-07

15.7.4 The location and characteristics of vapor ignition sources in and around the plant shall be surveyed and documented as follows:

(1) The probabilities of ignition sources being active during the dispersion of a vapor cloud shall be assessed and approved
(2) The probabilities, including conditional probabilities of occurrence of various environmental parameters, determined pursuant to the requirements of 15.7.1 through 15.7.4 shall be documented.

15.8 Hazard and Consequence Assessment.

15.8.1 The hazard consequences of releases identified pursuant to the requirements in 15.4 shall be assessed.

15.8.2 For each identified scenario of release, type of hazard behavior, weather, and environmental or other condition (e.g., time to detect, response time, blow-down, ignition of a vapor cloud at different distances, effects of obstructions, effects of passive mitigation techniques) impacting the hazard areas or hazard distances shall be determined by accepted methods, including those identified in 5.3.3.4 through 5.3.3.9.

15.8.3 The following types of hazards and calculations of extent of hazard shall be considered, as a minimum:

(1) Distance to limit concentration levels arising from gas/vapor dispersion
(2) Distance to limit heat flux or heat dosage levels arising from pool fire exposures
(3) Distance to limit heat flux or heat dosage levels arising from vapor fires
(4) Distance to limit heat flux or heat dosage levels arising from fireballs
(5) Distance to limit overpressure levels arising from explosions
(6) Distances to other hazards from rapid phase transition (RPT), toxic releases and so forth

15.8.3.1 Potential cascading damages from primary release scenarios identified in 15.5.1 within the plant boundaries shall be considered and evaluated. If the assessment identifies significant hazards from cascading in-plant failures or external out-of-plant events, the risk calculation shall include the cascading effects.

15.8.4 The distances to various types of hazards shall be calculated using mathematical models in accordance with 15.8.4.1 through 15.8.4.4.

15.8.4.1 Distances to safe levels of radiant heat fluxes and modified thermal dosage values specified in Table 15.8.4.1 and Table 15.8.4.2 shall be calculated with a model that meets the following criteria:

(1) Takes into account the physical phenomena observed and has been validated with available experimental data, including applicable experimental LNG fire published in the literature
(2) Has been published in an archival, peer-reviewed scientific journal in the related scientific/engineering disciplines, including, but not limited to, fluid dynamics, heat transfer, combustion, or fire science
(3) Has been verified to accurately represent the physics
(4) Has a scientific assessment of the details of the physics, analysis, and execution process
(5) Has been approved by the AHJ

Table 15.8.4.1 Radiant Heat Flux and Thermal Dosage Outside the Plant Boundary

Maximum Heat Flux Level (kW/m^2)	Maximum Modified Dosage Unit ($[kW/m^2]^{4/3}s$)	Consequences
5.0	500	At least 10 persons would suffer second-degree skin burns on at least 10% of their bodies within 30 seconds of exposure to the fire.
5.0	300	At least one person inside the building would suffer second-degree skin burns on at least 10% of the body within 30 seconds of exposure to the fire.
32	N/A	Loss of strength of structural steel exposed to the fire to an extent that its primary load-bearing capacity is reduced significantly over the duration of LNG fire being analyzed.

15.8.4.2* Distances to vapor dispersion to concentrations equal to the lower flammability limit (LFL) (volume concentration value 5 percent) shall be calculated using a model that is acceptable for use by the AHJ or a model that has been evaluated by an independent body using the Model Evaluation Protocol facilities published in the Fire Protection Research Foundation report "Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities." Alternatively, distances to the occurrences of ignition of a vapor cloud shall be calculated using a methodology that is acceptable to the AHJ.

15.8.4.3 Hazard distances for damage criteria specified in Table 15.8.4.3 for scenarios of vapor cloud explosions shall be based on mathematical models approved by the AHJ.

15.8.4.4 RPT and other phenomena hazard distances shall be determined with models approved by the AHJ.

15.8.5 For each identified scenario of release and type of hazard identified in Section 15.5 and hazard distances or areas evaluated in Section 15.8, the total number of persons located within the hazard distance or area shall be enumerated using public demographic or census data or other methodology approved by the AHJ.

15.8.6 Other hazard criteria for exposure to persons and property damage from potential exposures to different types of hazards indicated in Annex A shall be used as a guide in the hazard assessment required under Section 15.8.

15.8.7 The values of the hazard criteria used and the scientific justification or source of information shall be documented.

Table 15.8.4.2 Criteria for Property Damage Due to Radiant Heat from Fires

Exposed Structure	Type of Construction/Occupancy	Threshold Damage Criteria
Adjacent LNG container	Reinforced concrete	(1) Temperature of no part of the exposed concrete outer surface of the container structure shall exceed 1000°F (540°C) over the duration of the fire. (2) Temperature of steel reinforcements in pre-stressed concrete shall not exceed 570°F (300°C) over the duration of the fire.
Steel structures		Temperature shall not exceed 570°F (300°C) over the duration of the fire.
Wooden structures		Net heat flux into the structure shall not exceed 8115 Btu/hr-ft^2 (26,500 w/m^2) for unpiloted ignition or 4660 Btu/hr-ft^2 (14,700 w/m^2) for piloted ignition.

15.9 Risk Result Presentation.

15.9.1 Risk Contours of Constant Individual Risks.

15.9.1.1 The individual risk values for various combinations of release scenarios, materials released, and environmental and substrate conditions shall be combined with the various event occurrence probabilities to calculate the risk posed to an individual inside the plant boundary and outside the plant boundary.

15.9.1.2 Individual risk values shall be calculated for various distances in different compass directions from the event location.

15.9.1.3 Contours of constant individual risks shall be developed.

15.9.1.4 The uncertainty in calculating the individual risks shall be enumerated and presented.

15.9.2 Societal Risks on F-N Diagrams.

15.9.2.1 The potential number of exposed persons that may occur as a result of an event and combination of other parameters shall be determined using the approved local demographic data and the calculated hazard distances or areas.

15.9.2.2* The societal risk values shall be presented in the form of cumulative annual frequency of exceedance of a specified number of fatalities vs. number of fatalities.

15.9.2.3 Estimated error values in the calculation of both the cumulative annual frequency of specified casualty exceedance and the number of casualties shall be indicated on the F-N plots. The details of the error estimations shall be documented.

15.10 Risk Tolerability Criteria.

15.10.1 Individual risk acceptability criteria specified in Table 15.10.1 shall be used.

15.10.2* The societal risk acceptability criteria specified in Table 15.10.2 and illustrated in Figure 15.10.2 shall be used.

15.10.3 The acceptability criteria used in sections 15.10.1 and 15.10.2 shall be suitably modified taking into consideration the geographic location of the site and other local risk acceptability norms, if any.

Table 15.8.4.3 Blast Damage Criteria

Overpressure Damage Category	Reflected Damage Overpressure (N/m^2) Lower Limit	Upper Limit
Window glass damage	250	4,000
Damage to doors, cladding, and persons	5,000	10,000
Severe structural damage to buildings	15,000	20,000
Severe injury to people	25,000	50,000*

*Complete demolition of a building.

15.10.4 The criteria used for the tolerable individual risk and the societal risk, as modified, shall be approved.

15.11 Risk Mitigation Approaches.

15.11.1* In the case that the calculated risks are in the unacceptable region or lie in regions between the lower and upper bound acceptable ranges, reduction of risks to tolerable levels shall be considered by implementing additional mitigation measures.

15.11.2* Mitigation measures shall include, but not limited to, incorporation of the latest technology and instruments in plant design, improved equipment layout design, use of upgraded equipment, improved spill notification and emergency response procedures, and operational changes.

15.11.3* Mitigation measures proposed shall be approved.

Table 15.10.1 Criteria for Tolerability of Individual Risk (IR) from Injury Due to Exposure to Dangerous Dose or Higher

Criterion Annual Frequency	Remarks
Zone 1 IR > 10^{-5}	Not permitted: Residential, office, and retail Permitted: Occasionally occupied developments (e.g., pump houses, transformer stations)
Zone 2 $10^{-6} \leq$ IR $\leq 10^{-5}$	Not permitted: Shopping centers, large-scale retail outlets, restaurants, etc. Permitted: Work places, retail and ancillary services, residences in areas of 28 to 90 persons/hectare density
Zone 3 $3 \times 10^{-7} \leq$ IR $\leq 10^{-6}$	Not permitted: Churches, schools, hospitals, major public assembly areas, and other sensitive establishments Permitted: All other structures and activities

Table 15.10.2 Criteria for Tolerability of Societal (Fatalities) Risks

Criterion Annual Frequency (CAF)	Remarks
F = 10^{-4}, N = 10 Slope = −1	Unacceptable above the line defined by the CAF column
F = 10^{-6}, N = 10 Slope = −1	Broadly acceptable below the line defined by the CAF column
ALARP	Acceptable with AHJ review in the region between the two lines above

F = Annual probability of experiencing N or more fatalities

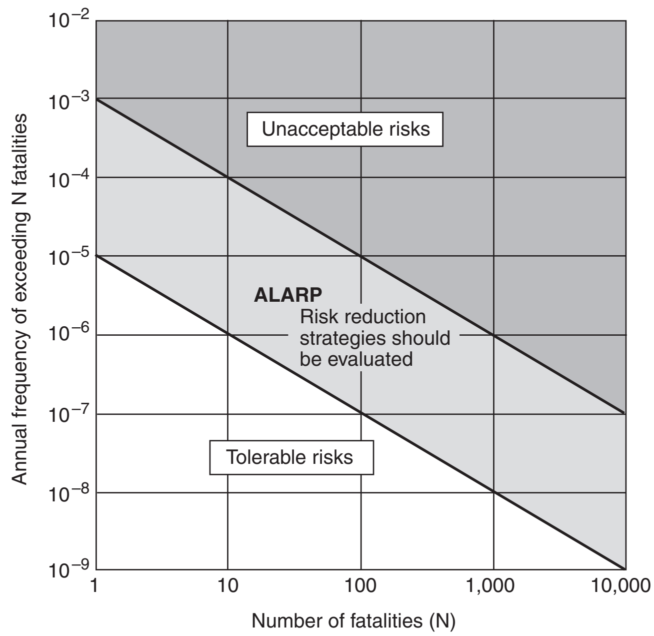


FIGURE 15.10.2 Acceptability Regions of Societal (Injury) Risk in the F-N Domain.

Annex A Explanatory Material

Annex A is not a part of the requirements of this NFPA document but is included for informational purposes only. This annex contains explanatory material, numbered to correspond with the applicable text paragraphs.

A.1.1 This standard establishes essential requirements and standards for the design, installation, and safe operation of liquefied natural gas (LNG) facilities. It provides guidance to all persons concerned with the construction and operation equipment for the production, storage, and handling of LNG. It is not a design handbook, and competent engineering judgment is necessary for its proper use.

At sufficiently low temperatures, natural gas liquefies. At atmospheric pressure, natural gas can be liquefied by reducing its temperature to approximately −260°F (−162°C).

Upon release from the container to the atmosphere, LNG will vaporize and release gas that, at ambient temperature, has about 600 times the volume of the liquid. Generally, at temperatures below approximately −170°F (−112°C), the gas is heavier than ambient air at 60°F (15.6°C). However, as its temperature rises, it becomes lighter than air.

Note that the −260°F (−162°C) temperature value is for methane. If the other constituents are present, see 3.3.15. For information on the use of LNG as a vehicle fuel, see NFPA 52.

A.1.3 Departure from the requirements of this standard can be considered by the authority having jurisdiction on the basis of a risk assessment. In the case of such departures, approval will be contingent upon a demonstration of fitness for purpose in line with the principles of this standard and other applicable recognized standards as well as recognized and generally accepted good engineering practice.

A risk approach justification of alternatives can be applicable either to the LNG plant as a whole or to individual systems, subsystems, or components. The boundaries of the components and systems of the LNG plant to which a risk-based assessment is applied are to be logical. As appropriate, account must be given to remote hazards outside the bounds of the system under consideration. Such account must include incidents relating to remote hazards directly affecting or being influenced by the system under consideration. The authority having jurisdiction can consider the application of risk-based techniques in the design, construction, operation, and maintenance of the LNG plant.

Portions of the LNG plant not included in the risk assessment are to comply with the applicable parts of this standard.

Designers, fabricators, constructors, and operators requesting approval by the authority having jurisdiction are responsible for the following:

(1) Risk acceptance criteria
(2) Hazard identification
(3) Risk assessment
(4) Risk management

A.1.5 If a value for a measurement as given in this standard is followed by an equivalent value in other units, the first stated value should be regarded as the requirement. A given equivalent value should be considered to be approximate.

A.2.1 The intent of the committee is to adopt the latest edition of the referenced publications unless otherwise stated.

A.3.2.1 Approved. The National Fire Protection Association does not approve, inspect, or certify any installations, procedures, equipment, or materials; nor does it approve or evaluate testing laboratories. In determining the acceptability of installations, procedures, equipment, or materials, the authority having jurisdiction may base acceptance on compliance with NFPA or other appropriate standards. In the absence of such standards, said authority may require evidence of proper installation, procedure, or use. The authority having jurisdiction may also refer to the listings or labeling practices of an organization that is concerned with product evaluations and is thus in a position to determine compliance with appropriate standards for the current production of listed items.

A.3.2.2 Authority Having Jurisdiction (AHJ). The phrase "authority having jurisdiction," or its acronym AHJ, is used in NFPA documents in a broad manner, since jurisdictions and approval agencies vary, as do their responsibilities. Where public safety is primary, the authority having jurisdiction may be a federal, state, local, or other regional department or individual such as a fire chief; fire marshal; chief of a fire prevention bureau, labor department, or health department; building official; electrical inspector; or others having statutory authority. For insurance purposes, an insurance inspection department, rating bureau, or other insurance company representative may be the authority having jurisdiction. In many circumstances, the property owner or his or her designated agent assumes the role of the authority having jurisdiction; at government installations, the commanding officer or departmental official may be the authority having jurisdiction.

A.3.3.4.3.1 Double Containment Tank System. A double containment tank system consists of a liquidtight and vaportight primary tank system, which is itself a single containment tank system, built inside a liquidtight secondary liquid container. The primary liquid container is of low-temperature metal or prestressed concrete. The secondary liquid container is designed to hold all the liquid contents of the primary container in the event of leaks from the primary container, but it is not intended to contain or control any vapor resulting from product leakage from the primary container. The annular space between the primary container and the secondary container must not be more than 20 ft (6 m). The secondary liquid container is constructed either from metal or of prestressed concrete. Refer to API 625, *Tank Systems for Refrigerated Liquefied Gases,* for further definition.

A.3.3.4.3.2 Full Containment Tank System. A full containment tank system consists of a liquidtight primary container and a liquidtight and vaportight secondary container. Both are capable of independently containing the product stored. The primary liquid container is of low-temperature metal or prestressed concrete. The secondary container must be capable of both containing the liquid product and controlling the vapor resulting from evaporation in the event of product leakage from the primary liquid container.

The secondary liquid container and roof are constructed either from metal or of prestressed concrete. Where concrete outer tanks are selected, vapor tightness during normal service must be ensured through the incorporation of a warm temperature vapor barrier. Under inner tank leakage (emergency) conditions, the material of the secondary concrete tank vapor barrier material will be exposed to cryogenic conditions. Vapor barrier liners are not expected to remain vaportight in this condition; however, the concrete must be designed to remain liquidtight and retain its liquid containment ability. Product losses due to the permeability of the concrete are acceptable in this case. For certain low temperature products, significant design issues arise at monolithically connected outer tank base-to-wall joints due to the mechanical restraint offered by the base. To mitigate these issues, it is normal practice to include a secondary liquid containment bottom and thermal corner protection to protect and thermally isolate this monolithic area from the cold liquid and provide liquid tightness.

Refer to API 625 for further definition.

A.3.3.4.3.3 Membrane Containment Tank System. A membrane containment tank system consists of a thin metal liquidtight barrier resting against load-bearing thermal insulation and supported by a free-standing outer pre-stressed concrete container.

In normal conditions, primary liquid and vapor containment is provided by a thin metallic barrier that is structurally supported via load-bearing insulation on an outer pre-stressed concrete container. Under these conditions, primary vapor containment is provided by a thin metallic barrier that is connected to the metallic roof liner.

In emergency conditions, the secondary liquid and vapor containment is provided by an outer pre-stressed concrete container and metallic roof liner. The outer container must be capable of both containing the liquid product and controlling the vapor resulting from evaporation. In this instance, the vapor generated from the leakage is discharged through pressure relief valves located in the roof. Vapor losses due to permeability through the outer pre-stressed concrete are acceptable while the wall is containing liquid in the event of leakage from the thin metal barrier and insulation system.

The roof of the outer pre-stressed concrete container can be concrete or steel. Significant design issues arise at the monolithic base-to-wall connection due to the mechanical restraint offered by the base. To mitigate these issues, a secondary liquid containment barrier inside the insulation system across the entire bottom and part of the wall in the vicinity of the base-to-wall joint is to be provided to protect and thermally isolate this area from the cold liquid and provide liquid-tightness. Other alternatives of the monolithic base-to-wall connection are described in ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*.

A.3.3.4.3.4 Single Containment Tank System. A single containment tank system incorporates a liquidtight container and a vapor-tight container. It can be a liquidtight and vaportight single-wall tank or a tank system comprising an inner container and an outer container, designed and constructed so that only the inner container is required to be liquidtight and contain the liquid product. The outer container, if any, is primarily for the retention and protection of the insulation system from moisture and may hold the product vapor pressure, but it is not designed to contain the refrigerated liquid in the event of leakage from the inner container. The primary liquid container is constructed of low-temperature metal or prestressed concrete. The outer tank (if any) must be vapor-tight. It is normally made from carbon steel, and it is referenced in this standard in various contexts as the warm vapor container or the purge gas container. A single containment tank system is surrounded by a secondary containment (normally a dike wall) that is designed to retain liquid in the event of leakage.

Refer to API 625 for further definition.

A.3.3.8 Engineering Design. The engineering design conforms to regulatory requirements and includes all necessary specifications, drawings, and supporting documentation. The engineering design is developed from process, mechanical, civil, structural, fire protection, corrosion, control, and electrical requirements and other specifications.

A.3.3.10 Fire Protection. Fire protection covers measures directed at avoiding the inception of fire or the escalation of an incident following the accidental or inadvertent release of LNG and other flammables.

A.3.3.16 LNG Facility. The following describes the distinctions in the terms *component*, *LNG facility*, and *LNG plant*:

Several *components* (piping, flanges, fittings, valves including relief valves, gaskets, instrumentation, pumps, compressors, heat exchangers, motors, engines, turbines, electrical field wiring, etc.) installed and designed to function as one unit (storage, vaporization, liquefaction, transfer, etc.) are referred to as an *LNG facility*.

A collection of LNG facilities (storage, vaporization, liquefaction, transfer, etc.) co-located on a site is referred to as an *LNG plant*.

Components that function as a unit for purposes of serving an entire LNG plant (such as electrical systems, fire protection systems, security systems, etc.) can be referred to as LNG plant systems.

A.3.3.27 Transfer Area. Transfer areas do not include product sampling devices or permanent plant piping.

A.3.3.29 Vacuum-Jacketed. This is an insulating alternative for cryogenic piping and containers. If designed appropriately, this feature can satisfy the need for secondary containment for the inner piping.

A.3.3.30 Vaporizer. A pressure-building coil that is integral to a container is not considered to be a vaporizer in the context of NFPA 59A.

A.4.6 The provisions of 4.6 do not require inherently noncombustible materials to be tested in order to be classified as noncombustible materials. [***101,*** A.4.6.13]

A.4.6(1) Examples of such materials include steel, concrete, masonry, and glass. [***101,*** A.4.6.13.1(1)]

A.5.2 The following factors should be considered in the selection of plant site locations:

(1) Provision for minimum clearances as stated in this standard between LNG containers, flammable refrigerant storage tanks, flammable liquid storage tanks, structures, and plant equipment, with respect to both plant property lines and each other
(2) The degree that the LNG plant can, within limits of practicality, be protected against forces of nature
(3) Other factors applicable to the specific site that have a bearing on the safety of LNG plant personnel and the surrounding public

The review of such factors should include an evaluation of potential incidents and safety measures incorporated in the design or operation of the LNG plant.

A.5.2.4 New plant site locations should avoid flood hazard areas. In the United States, maps that delineate special flood hazard areas are maintained by local officials or can be ordered or viewed online at FEMA's Map Store at http://www.fema.gov. Accessibility to the plant can be limited during conditions of flooding. Where encroachment into a flood hazard area is unavoidable, measures to minimize flood exposure and damage to the site and facilities should be investigated. Flood loads are outlined in ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. Structures, including tanks and containers, must be designed and constructed to prevent flotation, collapse, permanent lateral movement, and loss of contents during conditions of flooding.

A.5.3.2.5 Paragraph 7.2.1.1 requires compliance with API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*. API 625, paragraph 5.6, requires the selection of storage concept to be based on a risk assessment. API 625, Annex C, discusses implications of a release of liquid from the primary liquid container and provides specific discussion related to each containment type. API 625, Annex D, provides guidance for selection of storage concepts as part of the risk assessment including external and internal events and hazards to be evaluated. Paragraph D.3.2.2 discusses the possibility of sudden failure of the inner tank and advises, "If extra protection from brittle fracture [or unabated ductile crack propagation] is desired, the general practice is to increase" the primary container toughness. Available materials meeting the required specifications of API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q, and of this standard for LNG service are considered to have crack-arrest properties at LNG service temperature and stress levels. Therefore, rapid failure of a steel primary container meeting this standard is not considered credible. In membrane containment tank systems, brittle fracture of membrane material is typically not a pertinent hazard for membrane tanks. However, other hazards based on a risk assessment should be considered.

A.5.3.3.3 Methods that can be used to mitigate the effects of thermal radiation include the following:

(1) Affecting the burning rate of LNG
(2) Reducing the size of the LNG fire
(3) Reducing the radiant heat emission characteristics of the fire
(4) Impeding the transmission of the radiant heat from the fire to the exposed objects
(5) Other approved methods

A.5.3.3.4 Several models are available to determine the thermal radiation distance required by 5.3.3.4. These include but are not limited to the following: