NFPA 59A

Standard for the

Production, Storage, and Handling of Liquefied Natural Gas

(LNG)

2006 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 and acted on by NFPA at its June Association Technical Meeting held June 6–10, 2005, in Las Vegas, NV. It was issued by the Standards Council on July 29, 2005, with an effective date of August 18, 2005, and supersedes all previous editions.

This edition of NFPA 59A was approved as an American National Standard on August 18, 2005.

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 the 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, this 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 its standard 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 this purpose. The 1971 edition was the first edition developed under the broadened scope. Subsequent editions were adopted in 1972, 1975, 1979, 1985, 1990, 1994, 1996, and 2001.

The 2006 edition includes revisions in compliance with the *Manual of Style for NFPA Technical Committee Documents*, such as providing only administrative requirements in Chapter 1, referenced publications in Chapter 2, definitions in Chapter 3, and general requirements in Chapter 4. Former Chapters 2 through 11 have been renumbered as Chapters 5 through 14. In addition, editorial revisions were made to make the text more clear.

Chapter 5 has been revised to cover double and full containment LNG storage containers. Definitions of these types of containers have also been added to the standard. Seismic design criteria for LNG containers have been revised to correlate with the requirements of ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. Chapter 11 has been revised to add requirements for a contingency plan for potential LNG marine transfer incidents.

Technical Committee on Liquefied Natural Gas

Richard A. Hoffmann, *Chair*
Hoffmann & Feige, NY [SE]

Theodore C. Lemoff, *Secretary*
National Fire Protection Association, MA

Donald Barber, Enmat International (UK), United Kingdom [SE]
Rep. Institute of Gas Engineers/Institute of Energy

Christopher Bourne, Massachusetts Dept. of Telecommunications & Energy, MA [E]

Leon A. Bowdoin, Jr., Weaver's Cove Energy, MA [U]
Rep. NFPA Industrial Fire Protection Section

Don H. Coers, Coers and Company, IL [SE]

Brian L. Eisentrout, CB&I, IL [M]
Rep. Steel Plate Fabricators Association

Thomas J. Felleisen, U.S. Coast Guard, DC [E]

James J. Gaughan, American Bureau of Shipping, NY [E]

Ben Ho, BP Amoco Corporation, TX [U]

Stanley T. Kastanas, U.S. Department of Transportation, DC [E]

Francis J. Katulak, Distrigas of Massachusetts, LLC, MA [U]

Hans E. Kimmel, Ebara International Corporation, NV [M]

Nicholas A. Legatos, Preload Incorporated, NY [M]

Rep. American Concrete Institute

James P. Lewis, Project Technical Liaison Associates, Inc., TX [SE]

Alex Pastuhov, AVP Corporation, AZ [SE]

Kenneth L. Paul, Chart Industries, Inc., NH [M]

Gilford W. Poe, ExxonMobil Development Company, TX [U]
Rep. American Petroleum Institute

James J. Regan, Starr Technical Risks Agency Inc., IL [I]

Michael F. Schmidt, Tyco Suppression Systems, WI [M]
Rep. Fire Equipment Manufacturers' Association

Gregory J. Schneller, KeySpan Energy, NY [U]
Rep. American Gas Association

Chris Smith, Southern LNG, an El Paso Company, GA [U]
Rep. Interstate Natural Gas Association of America

James H. Stannard, Jr., Stannard & Company, GA [SE]

Ronald W. Tanner, Trunkline LNG Company, LLC, LA [U]
Rep. American Gas Association

Joseph E. Zanoni, Baker Engineering & Risk Consultants, Inc., TX [SE]

Alternates

Jeffrey P. Beale, CH-IV International, MD [SE]
(Alt. to J. H. Stannard)

Allan M. Clarke, Duke Energy Corporation, TX [U]
(Alt. to R. W. Tanner)

Dale R. Edlbeck, Tyco Fire & Security/Ansul, WI [M]
(Alt. to M. F. Schmidt)

Thomas D. High, Chart Industries, Inc., NH [M]
(Alt. to K. L. Paul)

Christopher E. Humes, Southern LNG, an El Paso Company, GA [U]
(Alt. to C. Smith)

Charles P. (Chuck) Ivey, Atmos Energy, GA [U]

(Alt. to G. J. Schneller)

Jay J. Jablonski, HSB Professional Loss Control, TX [I]
(Alt. to J. J. Regan)

Thomas V. Rodante, Baker Engineering & Risk Consultants, Inc., TX [SE]
(Alt. to J. E. Zanoni)

Michael R. Schuller, Pitt-Des Moines, Inc., PA [M]
(Alt. to B. L. Eisentrout)

Nonvoting

Swapan Kumar Hazra, Hindustan Aegis LPG Bottling Co., Ltd., India [M]

Theodore C. Lemoff, NFPA Staff Liaison

This list represents the membership at the time the Committee was balloted on the final text of this edition. Since that time, changes in the membership may have occurred. A key to classifications is found at the back of the document.

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.

NFPA 59A
Standard for the
Production, Storage, and Handling of Liquefied Natural Gas (LNG)
2006 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 mandatory extracts are given in Chapter 2 and those for nonmandatory extracts are given in Annex E. Editorial changes to extracted material consist of revising references to an appropriate division in this document or the inclusion of the document number with the division number when the reference is to the original document. 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. (Reserved)

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 Metric Practices.

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

1.5.1 Where clearance distances are to be determined, the conversion from U.S. customary units to SI units shall be calculated to the nearest 0.5 m.

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

1.6 Referenced Standards.

Reference shall be 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.

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

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

1.6.3 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,* 2002 edition.

NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam,* 2005 edition.

NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems,* 2005 edition.

NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems,* 2004 edition.

NFPA 13, *Standard for the Installation of Sprinkler Systems,* 2002 edition.

NFPA 14, *Standard for the Installation of Standpipe and Hose Systems,* 2003 edition.

NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection,* 2001 edition.

NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems,* 2003 edition.

NFPA 17, *Standard for Dry Chemical Extinguishing Systems,* 2002 edition.

NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection,* 2003 edition.

NFPA 22, *Standard for Water Tanks for Private Fire Protection,* 2003 edition.

NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances,* 2002 edition.

NFPA 30, *Flammable and Combustible Liquids Code,* 2003 edition.

NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines,* 2002 edition.

NFPA 54, *National Fuel Gas Code,* 2006 edition.

NFPA 58, *Liquefied Petroleum Gas Code,* 2004 edition.

NFPA 59, *Utility LP-Gas Plant Code,* 2004 edition.

NFPA 70, *National Electrical Code®,* 2005 edition.

NFPA 72®, *National Fire Alarm Code®,* 2002 edition.

NFPA *101®*, *Life Safety Code®,* 2006 edition.

NFPA 255, *Standard Method of Test of Surface Burning Characteristics of Building Materials,* 2006 edition.

NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids,* 2000 edition.

NFPA 600, *Standard on Industrial Fire Brigades,* 2005 edition.

NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems,* 2002 edition.

NFPA 1901, *Standard for Automotive Fire Apparatus,* 2003 edition.

NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems,* 2004 edition.

NFPA 5000®, *Building Construction and Safety Code®,* 2006 edition.

2.3 Other Publications.

2.3.1 ACI Publications.

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

ACI 301, *Specifications for Structural Concrete,* 1999.

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

ACI 311.4R, *Guide for Concrete Inspection,* 2000.

ACI 318, *Building Code Requirements for Reinforced Concrete,* 2005.

ACI 318R, *Building Code Requirements for Structural Concrete,* 2005.

ACI 350, *Code Requirements for Environmental Engineering Concrete Structures*, 2001.

ACI 372R, *Design and Construction of Circular Wire- and Strand-Wrapped Prestressed Concrete Structures,* 2003.

ACI 373R, *Design and Construction of Circular Prestressed Concrete Structures with Circumferential Tendons,* 1997.

ACI 506.2, *Specification for Materials, Proportioning, and Application of Shotcrete,* 1995.

2.3.2 API Publications.

American Petroleum Institute, 1220 L Street, N.W., Washington, DC 20005-4070.

API 6D, *Specification for Pipeline Valves,* 1994.

API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* 1990.

API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations,* 1989.

2.3.3 ASCE Publication.

American Society of Civil Engineers, 1801 Alexander Bell Drive, Reston, VA 20191.

ASCE 7, *Minimum Design Loads for Buildings and Other Structures,* 2002.

2.3.4 ASME Publications.

American Society of Mechanical Engineers, Three Park Avenue, New York, NY 10016-5990.

ASME *Boiler and Pressure Vessel Code,* 2004.

ASME B 31.3, *Process Piping,* 2004.

ASME B 31.5, *Refrigeration Piping,* 2001.

ASME B 31.8, *Gas Transmission and Distribution Piping Systems,* 2003.

2.3.5 ASTM Publications.

American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959.

ASTM A 82, *Standard Specification for Steel Wire, Plain, for Concrete Reinforcement,* 2002.

ASTM A 416, *Standard Specification for Steel Strand, Uncoated Seven-Wire for Prestressed Concrete,* 2002.

ASTM A 421, *Standard Specification for Uncoated Stressed-Relieved Steel Wire for Prestressed Concrete,* 2002.

ASTM A 496, *Standard Specification for Steel Wire, Deformed, for Concrete Reinforcement,* 2002.

ASTM A 615, *Standard Specification for Deformed and Plain Billet-Steel Bars for Concrete Reinforcement,* 2004.

ASTM A 722, *Standard Specification for Uncoated High-Strength Steel Bar for Prestressing Concrete,* 2005.

ASTM A 821, *Standard Specification for Steel Wire, Hand Drawn for Prestressing Concrete Tanks,* 1999.

ASTM A 966, *Standard Specification for Rail-Steel and Axle-Steel Deformed Bars for Concrete Reinforcement,* 2004.

ASTM A 1008, *Standard Specification for Steel, Sheet, Cold-Rolled, Carbon, Structural, High-Strength Low-Alloy and High-Strength Low-Alloy with Improved Formability,* 2005.

ASTM C 33, *Standard Specification for Concrete Aggregates,* 2003.

2.3.6 CGA Publications.

Compressed Gas Association, 4221 Walney Road, 5th Floor, Chantilly, VA 20151-2923.

CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids,* 2002.

CGA S-1.3, *Pressure Relief Device Standards — Part 3 — Compressed Gas Storage Containers,* 2003.

2.3.7 CSA Publications.

Canadian Standards Association, 5060 Spectrum Way, Mississauga, Ontario, L4W 5N6, Canada.

CSA A23.1, *Concrete Materials and Methods of Concrete Construction,* 2004.

CSA A23.3, *Design of Concrete Structures,* 2004.

CSA A23.4, *Precast Concrete — Materials and Construction/Qualification Code for Architectural and Structural Precast Concrete Products,* 2004.

CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code,* 2003.

CSA C22.1, *Canadian Electrical Code,* 2002.

CSA G30.5, *Welded Steel Wire Fabric for Concrete Reinforcement,* 1998.

CSA G30.18, *Billet-Steel Bars for Concrete Reinforcement,* 2000.

G279, *Steel for Prestressed Concrete Tendons,* 1982.

2.3.8 GRI Publications.

Gas Research Institute publications available from GTI, 1700 South Mount Prospect Road,

Des Plaines, IL 60018.

GRI Report 0176, "LNGFIRE: A Thermal Radiation Model for LNG Fires," 1989.

GRI Report 0242, "LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model," 1989.

2.3.9 IEEE Publication.

Institute of Electrical and Electronics Engineers, Three Park Avenue, 17th Floor, New York, NY 10016-5997.

IEEE/ASTM SI 10, *Standard for Use of the International System of Units (SI): The Modern Metric System,* 2002.

2.3.10 NACE Publication.

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

NACE RP 0169, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems,* 2002.

2.3.11 NRC Publication.

National Research Council of Canada, Ottawa, Ontario, K1A 0R6.

National Building Code of Canada, 1995.

2.3.12 Other Publication.

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

2.4 References for Extracts in Mandatory Sections.

NFPA 52, *Vehicular Fuel Systems Code,* 2006 edition.

NFPA 220, *Standard on Types of Building Construction,* 2006 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. A document, the main text of which contains only mandatory provisions using the word "shall" to indicate requirements and which is in a form generally suitable for mandatory reference by another standard or code or for adoption into law. Nonmandatory provisions shall be located in an appendix or annex, footnote, or fine-print note and are not to be considered a part of the requirements of a standard.

3.3 General Definitions.

3.3.1 Barrel. A unit of volume. One barrel equals 42 U.S. gal, or 5.615 ft^3 (0.159 m^3).

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

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

3.3.4 Components. A part, or a system of parts, that functions as a unit in an LNG plant 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.

3.3.5 Container. A vessel for storing liquefied natural gas.

3.3.5.1 Double Containment Container. A single containment container surrounded by and within 20 ft (6 m) of an opening to the atmosphere wall (secondary container) and designed to contain LNG in the event of a spill from the primary or inner container.

3.3.5.2 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.

3.3.5.3 Full Containment Container. A container in which the inner (primary) container is surrounded by a secondary container designed to contain LNG in the event of a spill from the inner container and where 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.

3.3.5.4 Membrane Container. A container that has a non-self-supporting thin layer (membrane) inner tank that is supported through insulation by an outer tank.

3.3.5.5 Prestressed Concrete Container. A concrete container in which the stresses created by the different loads or loading combinations do not exceed the allowable stresses.

3.3.5.6 Single Containment Container. A single wall container or a double wall container where only the primary or inner container is designed to contain LNG.

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

3.3.7 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.

3.3.8 Dike. A structure used to establish an impounding area or containment. [**52,** 2006]

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

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3.3.11 Flame Spread Index. A number obtained according to NFPA 255, *Standard Method of Test of Surface Burning Characteristics of Building Materials*. [**220,** 2006]

3.3.12* G. The normal or standard constant of gravity.

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, or nitrogen. [**52,** 2006]

3.3.16 LNG Plant. A facility whose components can be used to store, condition, liquefy, or vaporize natural gas.

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

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

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3.3.19 Noncombustible Material. A material that, in the form in which it is used and under the conditions anticipated, will not ignite, burn, support combustion, or release flammable vapors when subjected to fire or heat. Materials that are reported as passing ASTM E 136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C,* shall be considered noncombustible materials.

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

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3.3.21 Tank Vehicle. See 3.3.3, Cargo Tank Vehicle.

3.3.22* 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.

3.3.23 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.

3.3.24 Vaporizer.

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

3.3.24.2 Heated Vaporizer. A vaporizer that derives its heat from the combustion of fuel, electric power, or waste heat, such as from boilers or internal combustion engines.

3.3.24.2.1 Integral Heated Vaporizer. A heated vaporizer in which the heat source is integral to the actual vaporizing exchanger (including submerged combustion vaporizers).

3.3.24.2.2 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.

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

3.3.25 Water Capacity The amount of water at 60°F (16°C) required to fill a container. [**52,** 2006]

Chapter 4 General Requirements

4.1 Training of Personnel.

Persons engaged in the production, handling, and storage of LNG shall be trained in the hazards and properties of LNG.

4.2 Training Plan.

4.2.1 Every operating plant shall have a written training plan to instruct all LNG plant personnel.

4.2.1.1 The training plan shall include carrying out the emergency procedures that relate to their duties at the LNG plant as set out in the procedure manual referred to in 14.2.1 and providing first aid.

4.2.1.2 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 plant

(2) The characteristics and potential hazards of LNG and other hazardous fluids involved in operating and maintaining the LNG plant, including the serious danger from

frostbite that can result from contact with LNG or cold refrigerants

(3) Methods of carrying out their duties of maintaining and operating the LNG plant as set out in the manual of operating and maintenance procedures referred to in 13.18.2 and 13.18.4

(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

4.2.2 Each LNG facility shall have a written plan to keep the personnel at its LNG plant up-to-date on the function of the systems, fire prevention, and security at the LNG plant, and refresher training shall be required at intervals that do not exceed 2 years.

4.2.3 A record of all training shall be maintained for each employee of an LNG plant, and the records shall be maintained for at least 2 years after the date that the employee ceases to be employed at the LNG plant.

4.2.4 All LNG plant personnel shall meet the following requirements:

(1) LNG plant personnel shall receive the training referred to in Section 4.2.

(2) LNG plant personnel shall have experience related to their assigned duties.

4.2.5 Any person who has not completed the training or received experience set out in Section 4.2 shall be under the control of trained personnel.

4.3 Corrosion Control Overview.

4.3.1 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.

4.3.2 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

4.4 Control Center.

4.4.1 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 4.4.

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

(1) It shall be located apart from or be protected from other LNG facilities 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) Each control center 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 control center is located at an LNG plant, each control center shall have more than one means of communication with every other center.

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

4.5 Sources of Power.

4.5.1 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.

4.5.2 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.

4.6 Records.

4.6.1 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.

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

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

Chapter 5 Plant Siting and Layout

5.1* Plant Site Provisions.

5.1.1 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

5.1.2 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.

5.1.3 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.

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

5.2 Site Provisions for Spill and Leak Control.

5.2.1 General.

5.2.1.1 Provisions shall be made to minimize the possibility of the accidental discharge of LNG at containers endangering adjoining property or important process equipment and structures or reaching waterways, in accordance with one of the following methods:

(1) An impounding area surrounding the container(s) that is formed by a natural barrier, dike, impounding wall, or combination thereof complying with Sections 5.2 and 5.3

(2) An impounding area formed by a natural barrier, dike, excavation, impounding wall, or combination thereof complying with Sections 5.2 and 5.3 plus a natural or man-made drainage system surrounding the container(s) that complies with Sections 5.2 and 5.3

(3) Where the container is constructed below or partially below the surrounding grade, an impounding area formed by excavation complying with Sections 5.2 and 5.3

5.2.1.2 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

5.2.1.3 If impounding areas also are required in order to comply with 5.1.3, such areas shall

be in accordance with Sections 5.2 and 5.3.

5.2.1.4 The provisions of 5.1.3, 5.2.1.1, and 5.2.1.2 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.

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

5.2.2 Impounding Area and Drainage System Design and Capacity.

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

(1) For an impoundment serving a single tank, *V* equals 110 percent of the LNG tank's maximum liquid capacity.

(2) For an impoundment serving more than one tank, *V* equals 100 percent of all tanks or 110 percent of the largest tank's maximum liquid capacity, whichever is greater.

(3) If the dike is designed to account for a surge in the event of catastrophic failure, *V* equals 100 percent.

5.2.2.2 Impounding areas that serve only vaporization, process, or LNG transfer areas shall have a minimum volumetric capacity equal to the greatest volume of LNG, flammable refrigerant, or flammable liquid that can be discharged into the area during a 10-minute period from any single accidental leakage source or during a shorter time period based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction.

5.2.2.3 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.

5.2.2.4 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.

5.2.2.5 Dikes and impounding walls shall meet the following requirements:

(1) Dikes and impounding walls shall be constructed of compacted earth, concrete, metal, or other materials.

(2) Dikes shall be mounted integral to the container, installed against the container, or independent of the container.

(3) 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.

(4) Where the outer shell of a double-wall tank complies with the requirements of

5.2.1.1, the dike shall be either the outer shell or as specified in 5.2.1.1.

(5) Where the containment integrity of such an outer shell can be affected by an inner tank failure mode, an additional impounding area that otherwise satisfies the requirements of 5.2.1.1 shall be provided.

5.2.2.6 Double and full containment containers 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.

(A) In the case of a fire confined to the inner tank, the secondary container wall shall retain sufficient structural integrity to prevent collapse, which can cause damage to and leakage from the primary container.

(B) The tanks shall also be designed and constructed such that in the case of a fire in the primary or secondary container of 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.

5.2.2.7 Double and full containment containers shall have no pipe penetrations below the liquid level.

5.2.2.8 Dikes, impounding walls, and drainage channels for flammable liquid containment shall conform to NFPA 30, *Flammable and Combustible Liquids Code*.

5.2.2.9 The dike or impounding wall height and the distance from containers operating at 15 psi (100 kPa) or less shall be determined in accordance with Figure 5.2.2.9.

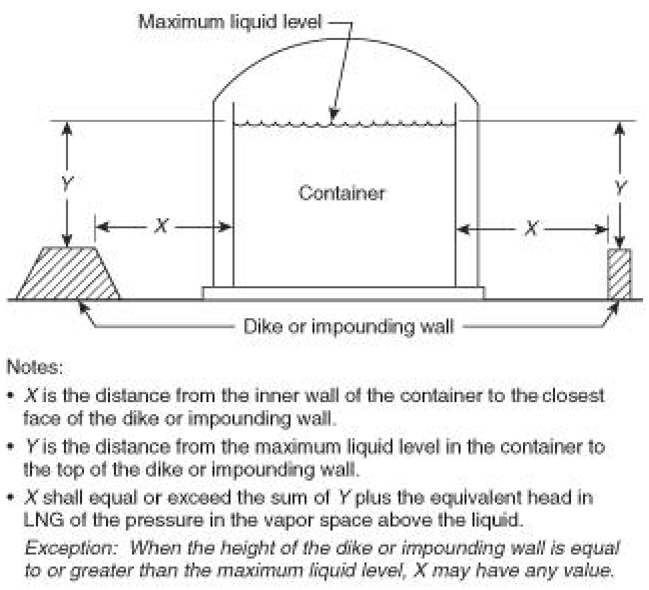

FIGURE 5.2.2.9 Dike or Impoundment Wall Proximity to Containers.

5.2.2.10 Water Removal.

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

(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.

5.2.2.10.2 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.

5.2.2.10.3 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

5.2.3 Impounding Area Siting.

5.2.3.1 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.

5.2.3.2 Thermal radiation flux from a fire shall not exceed the limits listed in Table 5.2.3.2 when atmospheric conditions are 0 (zero) windspeed, 70°F (21°C) temperature, and 50 percent relative humidity.

Table 5.2.3.2 Thermal Radiation Flux Limits to Property Lines and Occupancies

Thermal Radiation Flux		
Btu/hr/ft^2	W/m^2	Exposure
1,600	5,000	A property line 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 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 of 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 that can be built upon for a fire over an impounding area[b]

[a]See 5.2.3.5 for design spill.
[b]The requirements for impounding areas are located in 5.2.2.1.
[c]See NFPA *101*, *Life Safety Code*, or *NFPA 5000*, *Building Construction and Safety Code*, for definitions of occupancies.

5.2.3.3 Thermal radiation distances shall be calculated in accordance with one of the following:

(1) The Gas Research Institute's GRI Report 0176, "LNGFIRE: A Thermal Radiation Model for LNG Fires," which is also available as the "LNGFIRE III" computer

model produced by GRI, or alternative models that take into account the same physical factors and have been validated by experimental test data as follows:

(a) 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.

(b) 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.

(2) A model that incorporates the following:

(a) Impoundment configuration, wind speed and direction, humidity, and atmospheric temperature

(b) Validation by experimental test data appropriate for the size and conditions of the hazard to be evaluated

(c) Acceptance by the authority having jurisdiction

(3) Where the ratio of the major and minor dimensions of the impoundment does not exceed 2, the following formula:

$$d = F\sqrt{A}$$

where:

d = distance from the edge of impounded LNG [ft(m)]
F = flux correlation factor equal to the following:
3.0 for 1600 Btu/(hr · ft^2)
2.0 for 3000 Btu/(hr · ft^2)
0.8 for 10,000 Btu/(hr · ft^2)
A = surface area of impounded LNG [ft^2(m^2)]

5.2.3.4 The spacing of an LNG tank impoundment to the property line that can be built upon shall be such that, in the event of an LNG spill as specified in 5.2.3.5, an average 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 calculations using one of the following:

(1) The model described in GRI Report 0242, “LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model”

(2) A model that incorporates the following:

(a) Physical factors influencing LNG vapor dispersion, including, but not limited to, gravity spreading, heat transfer, humidity, wind speed and direction, atmospheric stability, buoyancy, and surface roughness

(b) Validation by experimental test data appropriate for the size and conditions of

the hazard to be evaluated

(c) Acceptance by the authority having jurisdiction

(A) The computed distances shall include calculations based on one of the following:

(1) 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

(2) The Pasquill-Gifford atmospheric stability, Category F, with a 4.5 mph (2 m/sec) wind speed

(B) 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).

(C) 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.

(D) 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.

5.2.3.5 The design spill shall be determined in accordance with Table 5.2.3.5.

Table 5.2.3.5 Design Spill

Container Penetration	Design Spill	Design Spill Duration
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 opening is 0. For SI units, use the following fo $q = \frac{1.06}{10,000} d^2 \sqrt{h}$ until the differential head acting opening is 0.
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 that could be pumped into the impounding area with the contai withdrawal pump(s) delivering tl rated capacity as follows: (1) For 10 minutes if surveillanc shutdown is demonstrated and a by the authority having jurisdicti (2) For the time needed to empty container where surveillance and shutdown is not approved

Table 5.2.3.5 Design Spill

Container Penetration	Design Spill	Design Spill Duration
Containers with penetrations below the liquid level with internal shutoff valves in accordance with 9.3.2.5	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 fo $q = \frac{1.06}{10{,}000} d^2 \sqrt{h}$ for 10 minutes.
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 ti based on demonstrable surveillar shutdown provisions acceptable t authority having jurisdiction
Full or double containment containers with concrete secondary containers	No design spill	None

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

5.2.3.6 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.

5.2.3.7 Containers with an aggregate storage of 70,000 gal (265 m^3) or less on one site shall be installed either in accordance with 5.2.3 or in accordance with Table 5.2.4.1 where all connections are equipped with automatic failsafe 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 failsafe valve or with two backflow check valves.

(C) Automatic failsafe 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.

5.2.3.8 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).

5.2.4 Container Spacing.

5.2.4.1 The minimum separation distance between LNG containers or tanks containing flammable refrigerants and exposures shall be in accordance with Table 5.2.4.1 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.

Table 5.2.4.1 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
501–2000	≥1.9–7.6	15	4.6	5	1.5
2001–18,000	≥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 shall 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 shall 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.

5.2.4.2 Double and full containment containers with concrete secondary containers shall have a separation distance to limit the incident thermal radiation flux from a fire within the primary or secondary container of an adjacent tank as follows:

(1) Steel wall and roofs: 4,700 Btu/ft^2/hr (15,000 W/m^2)

(2) Concrete walls: 9,500 Btu/ft^2/hr (30,000 W/m^2)

(A) The ambient conditions for thermal radiation flux shall be based on the conditions (temperature, wind speed, relative humidity) within the range expected for the site, calculated to produce the highest temperature in the secondary container structure.

(B) A water spray or deluge system shall be permitted to be used to limit the thermal radiation flux onto the structure, but in no event shall the separation distance be less than $^1/_2$ the diameter of the largest tank.

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

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

5.2.5 Vaporizer Spacing.

5.2.5.1 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 is either cooled down or being cooled down.

5.2.5.2 Integral heated vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon *(see 5.2.5.4)* and at least 50 ft (15 m) from the following:

(1) Any impounded LNG, flammable refrigerant, or flammable liquid *(see 5.2.4)* 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

5.2.5.3 Heaters or heat sources of remote heated vaporizers shall comply with 5.2.5.2.

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

5.2.5.5 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 5.2.4.1, assuming the vaporizer to be a container with a capacity equal to the largest container to which it is connected.

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

5.2.6 Process Equipment Spacing.

5.2.6.1 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.

5.2.6.2 Where control centers are located in a building housing flammable gas compressors,

the building construction shall comply with 5.3.1.

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

5.2.7 Loading and Unloading Facility Spacing.

5.2.7.1 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.

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

5.2.7.3 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.

5.3 Buildings and Structures.

5.3.1 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.

5.3.2 If rooms containing LNG and flammable fluids are located within or attached to buildings in which such fluids are not handled (e.g., control centers, shops), the common walls shall be limited to no more than two, shall be designed to withstand a static pressure of at least 100 psf (4.8 kPa), shall have no doors or other communicating openings, and shall have a fire resistance rating of at least 1 hour.

5.3.3 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 5.3.3.1 through 5.3.3.4.

5.3.3.1 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

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

5.3.3.3 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.

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

5.3.4 Buildings or structural enclosures not covered by Section 5.3 and 5.3.2 shall be located, or provision otherwise shall be made, to minimize the possibility of entry of flammable gases or vapors.

5.3.5 Where LNG portable 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) LNG transport vehicles complying with U.S. Department of Transportation (DOT) requirements shall be used as the supply container.

(2) All portable LNG equipment shall be operated by at least one person qualified by experience and training in the safe operation of these systems.

(3) All other operating personnel, at a minimum, shall be qualified by training.

(4) Each operator shall provide and implement a written plan of initial training to instruct all designated operating and supervisory personnel in the characteristics and hazards of LNG used or handled at the site, including low LNG temperature, flammability of mixtures with air, odorless vapor, boil-off characteristics, and reaction to water and water spray; the potential hazards involved in operating activities; and how to carry out the emergency procedures that relate to personnel functions and to provide detailed instructions on mobile LNG operations.

(5) 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.

(6) Portable or temporary containment means shall be permitted to be used.

(7) Vaporizer controls shall comply with 8.3.1, 8.3.2, and Section 8.4.

(8) Each heated vaporizer shall be provided with a means to shut off the fuel source remotely and at the installed location.

(9) Equipment and operations shall comply with 14.7.1, 14.7.2, Section 11.9, 11.10.1, 12.2.1, Section 12.3, 12.3.3, 12.3.4, 12.3.5, and 5.3.5(4), with the exception of the clearance distance provisions.

(10) The LNG facility spacing specified in Table 5.2.4.1 shall be maintained, except where necessary to provide temporary service on a public right-of-way or on property where clearances specified in Table 5.2.4.1 are not feasible and 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 5.3.5(10), flag persons shall be continuously on duty to direct such traffic.

(11) Provision shall be made to minimize the possibility of accidental ignition in the event of a leak.

(12) 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, *Standard for Portable Fire Extinguishers*.

(13) The site shall be continuously attended, and provisions shall be made to restrict public access to the site whenever LNG is present.

5.3.6 If odorization is required of the emergency facility, the restrictions of 5.2.4.1 shall not apply to the location of odorizing equipment containing 20 gal (7.6 L) of flammable odorant or less within the retention system.

5.4* Designer and Fabricator Competence.

5.4.1 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.

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

5.4.3 Designers, fabricators, and constructors of LNG facility equipment shall be competent in the design, fabrication, and construction of LNG containers, cryogenic equipment, piping systems, fire protection equipment, and other components of the facility.

5.4.4 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.

5.5* Soil Protection for Cryogenic Equipment.

LNG containers *(see 7.2.7)*, 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.

5.6 Falling Ice and Snow.

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

5.7 Concrete Materials.

5.7.1 Concrete used for construction of LNG containers shall be in accordance with Section 7.4.

5.7.2 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.

5.7.2.1 The design of the structures shall be in accordance with the provisions of 7.4.1.

5.7.2.2 The materials and construction shall be in accordance with the provisions of 7.4.2.

5.7.3 Pipe supports shall comply with Section 9.4.

5.7.4 Other Concrete Structures.

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

5.7.4.2 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 5.7.2.1 or 5.7.2.2.

5.7.5* Concrete for incidental nonstructural uses, such as slope protection and impounding area paving, shall conform to ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*.

5.7.6 Reinforcement 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*.

5.7.7 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.

Chapter 6 Process Equipment

6.1 Installation of Process Equipment.

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 fire fighting, and to facilitate dispersal of accidentally released liquids and gases

(2) Indoors, in enclosing structures that comply with Section 5.3 and 5.3.2

6.2 Pumps and Compressors.

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

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

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

6.2.4 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.

6.2.5 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 Flammable Refrigerant and Flammable Liquid Storage.

Installation of storage tanks for flammable refrigerants and liquids shall comply with NFPA 30, *Flammable and Combustible Liquids Code*; NFPA 58, *Liquefied Petroleum Gas Code*; NFPA 59, *Utility LP-Gas Plant Code*; API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*; or Section 5.2 of this standard.

6.4 Process Equipment.

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6.4.1 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.*

6.4.2 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, *Boiler, Pressure Vessel and Pressure Piping Code*, and shall be code-stamped.

6.4.3 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, *Boiler, Pressure Vessel and Pressure Piping Code*, where such components fall within the jurisdiction of the pressure vessel code.

6.4.4* Installation of internal combustion engines or gas turbines not exceeding 7500 horsepower per unit shall conform to NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*.

6.4.5 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.

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

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

6.4.6 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.

6.4.7 If gas is introduced, it shall not create a flammable mixture within the system.

Chapter 7 Stationary LNG Storage Containers

7.1 Inspection.

7.1.1 Prior to initial operation, containers other than ASME containers shall be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of this standard.

7.1.2 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.

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

7.2 Design Considerations.

7.2.1 General.

7.2.1.1 The following information shall be specified for each LNG container:

(1) Maximum allowable working pressure, including a margin above the normal operating pressure

(2) Maximum allowable vacuum

7.2.1.2 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).

7.2.1.3 All piping that is a part of an LNG container shall comply with Chapter 9.

(A) Container piping shall include all piping internal to the container, within insulation spaces and within void spaces, and external piping attached or connected to the container up to the first circumferential external joint of the piping.

(B) Inert gas purge systems wholly within the insulation spaces shall be exempt from compliance with Chapter 9.

(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 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."

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

7.2.1.5 Any portion of the outer surface area of an LNG container that accidentally could be exposed 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.

7.2.1.6 Where two or more containers are sited in a common dike, the container foundations shall be capable of withstanding contact with LNG or shall be protected against contact with an accumulation of LNG that might endanger structural integrity.

7.2.1.7 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).

7.2.1.8 Provisions shall be made for removal of the container from service.

7.2.2 Seismic Design of Field-Fabricated Containers.

7.2.2.1 A site-specific investigation shall be performed for all installations except those provided for in 7.2.3 to determine the characteristics of seismic ground motion and associated response spectra.

(A) The site-specific investigation 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 probabilistic maximum considered earthquake (MCE) shall be the motion having a 2 percent probability of exceedance within a 50-year period (mean recurrence interval of 2475 years), subject to the exception in 7.2.2.1(G).

(C) Using the MCE 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 response spectral acceleration for any period, T, shall correspond to a damping ratio that best represents the structure being investigated.

(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 those of the horizontal spectrum.

(F) If information is available, the corresponding ratio shall not be less than 1/2.

(G) Where the probabilistic spectral response ordinates for a 5 percent damped response spectrum having a 2 percent probability of exceedance within a 50-year period at $T = 0.2$ second or 1 second exceed the corresponding ordinates of the deterministic limit of

7.2.2.1(I), the MCE ground motion shall be the lesser of the following:

(1) The probabilistic MCE ground motion as defined in 7.2.2.1(B)

(2) The deterministic ground motion of 7.2.2.1(H), but not less than the deterministic limit ground motion of 7.2.2.1(I)

(H) The deterministic MCE ground motion response spectrum shall be calculated at 150 percent of the median 5 percent damped spectral response acceleration at all periods resulting from a characteristic earthquake on a known active fault within the region.

(I) The deterministic limit on MCE ground motion shall be taken as the response spectrum determined in accordance with the provisions of ASCE 7, *Minimum Design Loads for Buildings and Other Structures*, with the value of S_S (mapped MCE spectral response acceleration at short periods) taken as 1.5 G, the value of S_1 (mapped MCE spectral response acceleration at 1 second) taken as 0.6 G, and the values of F_a (short-period site coefficient at 0.2 second) and F_v (long-period site coefficient at 1 second) selected for the site class most representative of the subsurface conditions where the LNG facility is located.

7.2.2.2 The LNG container and its impounding system shall be designed for the following two levels of seismic ground motion:

(1) The safe shutdown earthquake (SSE) as defined in 7.2.2.3

(2) The operating basis earthquake (OBE) as defined in 7.2.2.4

7.2.2.3 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 ground motion defined in 7.2.2.1.

7.2.2.4* 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).

7.2.2.5 The two levels of ground motion defined in 7.2.2.3 and 7.2.2.4 shall be used for the earthquake-resistant design of the following structures and systems:

(1) An LNG container and its impounding system

(2) System components required to isolate the LNG container 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 7.2.2.5(1) or 7.2.2.5(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 an elastic response spectrum.

(C) Where used, response reduction factors applied in the OBE design shall be demonstrated not to reduce the performance criteria in 7.2.2.5(A).

(D) The SSE design shall provide for no loss of containment capability of the primary container, and it shall be possible to isolate and maintain the LNG container during and after the SSE.

(E) Where used, response reduction factors applied in the SSE design shall be demonstrated not to reduce the performance criteria in 7.2.2.5(D).

7.2.2.6 The impounding system shall, as a minimum, be designed to withstand an SSE while empty and an OBE while holding the volume, *V*, as specified in 2.2.2.1.

7.2.2.7 After an OBE or an SSE, there shall be no loss of containment capability.

7.2.2.8 An LNG container shall be designed for the OBE, and a stress-limit check shall be made for the SSE to ensure compliance with 7.2.2.5.

(A) OBE and SSE analyses shall include the effect of liquid pressure on buckling stability.

(B) Stresses for the OBE shall be in accordance with the document referenced in Section 7.3, 7.4, or 9.1, as applicable.

(C) Stresses for the SSE shall be subjected to the following limits:

(1) Stresses in metal containers shall be allowed to reach the specified minimum yield for the tensile conditions and critical buckling for the compression condition.

(2) Axial hoop stresses from unfactored loads in prestressed concrete containers shall not exceed the modulus of rupture for the tensile condition and shall not exceed 60 percent of the specified 28-day compressive strength for the compressive condition.

(3) Extreme fiber stresses from combined axial and bending hoop forces from unfactored loads in prestressed concrete containers shall not exceed the modulus of rupture for the tensile condition and shall not exceed 69 percent of the specified 28-day compressive strength for the compressive condition.

(4) Hoop tensile stresses in prestressed concrete containers shall not exceed the yield stress in non-prestressed reinforcement and shall not exceed 94 percent of the yield stress in prestressed reinforcement with the assumption of a cracked section.

7.2.2.9 After an SSE event, the container shall be emptied and inspected prior to resumption of container-filling operations.

7.2.2.10 The design of the LNG container and structural components shall incorporate a dynamic analysis that includes the effects of sloshing and restrained liquid.

(A) Container flexibility, including shear deformation, shall be included in the determination of the container response.

(B) Soil-structure interaction shall be included where the container is not founded on bedrock (Site Class A or B per ASCE 7, *Minimum Design Loads for Buildings and Other Structures*).

(C) Where the container is supported by pile caps, the flexibility of the pile system shall be considered in the analysis.

7.2.3 Shop-Built Containers.

7.2.3.1 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:

$$V = Z_c \times W$$

For design vertical force, P:

$$P = 2/3 Z_c \times W$$

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, *Maximum 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

(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 7.2.2.1 through 7.2.2.6 shall be followed.

7.2.3.2 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.

7.2.3.3 The requirements of 7.2.3 shall apply to ASME containers built prior to July 1, 1996, when reinstalled.

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

7.2.4 Wind, Flood, and Snow Loads.

(A) The wind, flood, and snow loads for the design of LNG storage containers shall be determined using the procedures outlined in ASCE 7, *Minimum Design Loads for Buildings and Other Structures.*

(B) Where a probabilistic approach is used, a 100-year mean occurrence interval shall be used.

(C) In Canada, the wind and snow loads for the design of LNG storage containers shall be determined using the procedure outlined in the *National Building Code of Canada.*

(D) For wind, the value in the *National Building Code of Canada* for a 100-year mean recurrence interval shall be used.

7.2.5 Container Insulation.

7.2.5.1 Exposed insulation shall be noncombustible, shall contain or inherently shall be a vapor barrier, shall be waterfree, 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 3.3.11.)*

7.2.5.2 The space between the inner tank and the outer tank shall contain insulation that is compatible with LNG and natural gas and that is noncombustible.

(A) A fire external to the outer tank shall not cause reduction of the insulation thermal conductivity due to melting or settling.

(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) 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.

7.2.6 Filling Volume. Containers designed to operate at a pressure in excess of 15 psi (100 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.

7.2.7 Foundations.

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

7.2.7.2 Prior to the start of design and construction of the foundation, a subsurface investigation shall be conducted by a soils engineer to determine the stratigraphy and

physical properties of the soils underlying the site.

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

7.2.7.4 The outer tank 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

7.2.7.5 Where an outer tank is in contact with the soil, 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.

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

7.2.7.7 A tank 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 tank foundation heating system (if provided) shall be installed.

7.2.7.8 The system in 7.2.7.7 shall be used to conduct a tank bottom temperature survey 6 months after the tank has been placed in service and annually thereafter, after an OBE and after the indication of an abnormally cool area.

7.3 Metal Containers.

7.3.1 Containers Designed for Operation at 15 psi (100 kPa) and Less.

7.3.1.1 Welded containers designed for not more than 15 psi (100 kPa) shall comply with API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks.*

7.3.1.2 API 620, Appendix Q, shall be applicable for LNG with the following changes:

(1) In Q-7.6.5, “twenty-five percent” shall be changed to “all.”

(2)* In Q-7.6.1 through Q-7.6.4, 100 percent examination of all vertical and horizontal butt welds associated with the container wall, except for the shell-to-bottom welds associated with a flat bottom container, shall be required.

(3) API 620, Appendix C, C.11, shall be a mandatory requirement.

7.3.2 Containers Designed for Operation at More Than 15 psi (100 kPa).

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

7.3.2.2 The insulation shall be evacuated or purged.

7.3.2.3 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 insulation is used, the design pressure shall be the sum of the required working pressure, 15 psi (100 kPa) for vacuum allowance, and the hydrostatic head of LNG.

(B) Where nonvacuum insulation is used, the design pressure shall be the sum of the required working pressure and the hydrostatic head of LNG.

(C) The inner tank 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 tank expands after an in-service period, the purging and operating pressure of the space between the inner and outer tanks, and seismic loads.

7.3.2.4 The outer tank 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 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 (100 kPa)

(2) Paragraph 3.6.2 of CGA 341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*

(C) 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 (100 kPa).

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

(E) The outer tank 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 (0.0034 cm^2/kg) of the water capacity of the inner tank, but the area shall not exceed 300 in.^{2} (2000 cm^2).

(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.

(F) Thermal barriers shall be provided to prevent the outer tank 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 not less than 2 hours.

(I) If insulation is used to achieve the fire resistance rating of not less than 2 hours, it shall be resistant to dislodgement by fire hose streams.

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

7.3.2.6 The expansion and contraction of the inner tank 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 tanks are within allowable limits.

7.3.2.7 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.

(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 tank 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.

7.3.2.8 The inner tank shall be supported concentrically within the outer tank 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 number of G (gravitational acceleration) to be encountered, multiplied by the empty mass of the inner tank.

(2) Operating load supports shall be designed for the total mass of the inner tank 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).

7.3.2.9 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.

7.3.2.10 Where threaded members are used, the minimum area at the root of the threads shall be used.

7.4 Concrete Containers.

7.4.1 Prestressed Container Structure.

7.4.1.1 The design of concrete containers shall comply with standards ACI 318, *Building Code Requirements for Reinforced Concrete,* or CSA A23.3, *Design of Concrete Structures.*

7.4.1.2 Allowable stresses for normal design considerations shall be based on room temperature-specified minimum strength values.

7.4.1.3 Tensile stresses (exclusive of direct temperature and shrinkage effects) in carbon steel reinforcing bars when exposed to LNG temperatures under design conditions shall be limited to the allowable stresses listed in Table 7.4.1.3.

Table 7.4.1.3 Allowable Stresses of Rebar

	Maximum Allowable Stresses*	
Bar Description No.	**psi**	**MPa**
ASTM A 615 (U.S.)		
4 and smaller	12,000	82.7
5, 6, and 7	10,000	68.9
8 and larger	8,000	55.2
CSA G30.18 (Canada)		
10 and smaller	12,000	82.7
15 and 20	10,000	68.9
25 and larger	8,000	55.2

*According to ASTM A 615, *Standard Specification for Deformed and Plain Billet-Steel Bars for Concrete Reinforcement,* and CSA G30.18, *Billet-Steel Bars for Concrete Reinforcement.*

7.4.1.4 Steel wire or strands, as specified in 7.4.2.4 and used as unstressed reinforcement, shall be designed with a maximum allowable stress as follows:

(1) Crack control applications — 30,000 psi (207 MPa)

(2) Other applications — 80,000 psi (552 MPa)

7.4.2 Materials Subject to LNG Temperature.

7.4.2.1 Concrete.

(A) Concrete shall be in accordance with the requirements of the following standards:

(1) In the United States, ACI 304R, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*, and ACI 318, *Building Code Requirements for Reinforced Concrete*

(2) In Canada, CSA A23.1, *Concrete Materials and Methods of Concrete Construction*, CSA A23.3, *Design of Concrete Structures*, and CSA A23.4, *Precast Concrete — Materials and Construction/Qualification Code for Architectural and Structural Precast Concrete Products*

(B) Tests on concrete shall be carried out for the compressive strength and for the coefficient of contraction of the concrete at the projected low temperature, unless prior test data on these properties are available.

7.4.2.2 Aggregate.

(A) Aggregate shall be specified by the following standards:

(1) In the United States, ASTM C 33, *Standard Specification for Concrete Aggregates*

(2) In Canada, CSA A23.1, *Concrete Materials and Methods of Concrete Construction*

(B) Aggregate shall be dense and physically and chemically sound to provide a high-strength and durable concrete.

7.4.2.3 Pneumatic Mortar. Pneumatic mortar shall be in accordance with ACI 506.2, *Specification for Materials, Proportioning, and Application of Shotcrete.*

7.4.2.4 High-Tensile-Strength Elements.

(A) High-tensile-strength elements for prestressed concrete shall meet the requirements of the following standards:

(1) In the United States, ASTM A 416, *Standard Specification for Steel Strand, Uncoated Seven-Wire for Prestressed Concrete*; ASTM A 421, *Standard Specification for Uncoated Stressed-Relieved Steel Wire for Prestressed Concrete*; ASTM A 722, *Standard Specification for Uncoated High-Strength Steel Bar for Prestressing Concrete*; or ASTM A 821, *Standard Specification for Steel Wire, Hand Drawn for Prestressing Concrete Tanks*

(2) In Canada, CSA G279, *Steel for Prestressed Concrete Tendons*

(B) Any materials acceptable for service at LNG temperature, such as those materials specified for primary components in API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q, or any material shown by test to be acceptable

for LNG service, shall be used.

(C) Material for permanent end anchorages shall maintain its structural capability at LNG temperatures.

7.4.2.5 Reinforcing Steel.

(A) Reinforcing steel for reinforced concrete shall be as specified by the following standards:

(1) In the United States, ACI 318, *Building Code Requirements for Reinforced Concrete*

(2) In Canada, ASTM A 82, *Standard Specification for Steel Wire, Plain, for Concrete Reinforcement*; ASTM A 496, *Specification for Steel Wire, Deformed, for Concrete Reinforcement*; and CSA G30.18, *Billet-Steel Bars for Concrete Reinforcement*

(B) The use of ASTM A 966, *Standard Specification for Rail-Steel and Axle-Steel Deformed Bars for Concrete Reinforcement*, materials shall not be permitted.

7.4.2.6 Nonstructural metallic barriers incorporated in, and functioning compositely with, prestressed concrete in direct contact with LNG during normal operations shall be of a metal classified for either "primary components" or "secondary components" in API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q, if the composite section is prestressed such that no significant tensile stresses are developed under any design loading condition.

7.4.2.7 Nonstructural metallic barriers incorporated in, and functioning compositely with, prestressed concrete serving primarily as moisture barriers for internally insulated tanks shall be of a metal classified for either "primary component" or "secondary component" service in API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix Q, or of steel conforming to ASTM A 1008, *Standard Specification for Steel, Sheet, Cold-Rolled, Carbon, Structural, High-Strength Low-Alloy and High-Strength Low-Alloy with Improved Formability*, if the composite section is prestressed such that no significant tensile stresses are developed under any design loading condition.

7.4.3 Construction, Inspection, and Tests.

7.4.3.1 Concrete LNG containers shall be built in accordance with the applicable requirements of the following standards and publications:

(1) In the United States, ACI 318R, *Building Code Requirements for Structural Concrete*; Section 9 of ACI 301, *Specifications for Structural Concrete*; ACI 372R, *Design and Construction of Circular Wire- and Strand Wrapped Prestressed Concrete Structures*; and ACI 373R, *Design and Construction of Circular Prestressed Concrete Structures with Circumferential Tendons*

(2) In Canada, CSA A23.3, *Design of Concrete Structures*

7.4.3.2 Concrete LNG containers shall be inspected in accordance with ACI 311.4R, *Guide for Concrete Inspection*, and Section 7.6 of this standard.

7.4.3.3 Metal components shall be constructed and tested in accordance with the applicable

provisions in Appendix Q of API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks.*

7.4.3.4 Other materials used in the construction of concrete LNG containers shall be qualified before use based on inspection and test.

7.5 Marking of LNG Containers.

7.5.1 Each container shall be identified by the attachment in an accessible location of a corrosion-resistant nameplate marked with the following information:

(1) Builder's name and date built

(2) Nominal liquid capacity (in barrels, gallons, or cubic meters)

(3) Design pressure for methane gas at top of container

(4) Maximum permitted density of liquid to be stored

(5) Maximum level to which container can be filled with stored liquid *(see 7.2.6)*

(6) Maximum level to which container can be filled with water for test, if applicable

(7) Minimum temperature in degrees Fahrenheit (Celsius) for which the container was designed

7.5.2 Storage containers shall have all penetrations marked with the function of the penetration.

7.5.3 Penetration markings shall be visible if frosting occurs.

7.6 Testing of LNG Containers.

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

7.6.1 Where no specific single construction code is applicable, the container designer shall provide a test procedure based on API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,*

7.6.2 Containers designed for pressures in excess of 15 psi [103 kPa(g)] 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 tank 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 tank shall be leak tested.

(4) Piping shall be tested in accordance with Section 9.6.

(5) Containers and associated piping shall be leak tested prior to filling the container with LNG.

7.6.3 Shop-fabricated containers designed for pressures in excess of 15 psi [103 kPa(g)] shall be pressure tested by the manufacturer prior to shipment to the installation site.

7.6.4 The inner tank of field-fabricated containers designed for pressures in excess of 15 psi [103 kPa(g)] shall be tested in accordance with the ASME *Boiler and Pressure Vessel Code* or CSA B51, *Boiler, Pressure Vessel and Pressure Piping Code.*

7.6.5 The outer tank of field-fabricated containers designed for pressures in excess of 15 psi [103 kPa(g)] shall be tested in accordance with Section 9.6.

7.6.6 Containers and associated piping shall be leak tested prior to filling the container with LNG.

7.6.7 After acceptance tests are completed, there shall be no field welding on the LNG containers.

(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.

7.7 Container Purging and Cooldown.

Before an LNG container is put into service, it shall be purged and cooled in accordance with Section 14.3.

7.8 Relief Devices.

7.8.1 ASME and API containers shall be equipped with vacuum and pressure relief valves as required by the code or standard of manufacture.

7.8.2 Relief devices shall communicate directly with the atmosphere.

7.8.3 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.

7.8.4 Each pressure and vacuum safety relief valve for LNG containers shall be able to be isolated from the container 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 container 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.

7.8.5 Pressure Relief Device Sizing.

7.8.5.1 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

7.8.5.2 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.

7.8.5.3* 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.

7.8.6 Vacuum Relief Sizing.

7.8.6.1 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

7.8.6.2 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 tank contents.

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

7.8.7 Fire Exposure.

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

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

For SI units:

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

where:

H = total heat influx [Btu/hr (watt)]
F = environmental factor from Table 7.8.7.1
A = exposed wetted surface area of the container [ft^2 (m^2)]
H_n = normal heat leak in refrigerated tanks [Btu/hr (watt)]

Table 7.8.7.1 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	$F = \frac{U(1660 - T_f)}{34{,}500}$
SI units	$F = \frac{U(904 - T_f)}{71{,}000}$

*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).

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

7.8.7.3* 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.

7.8.7.4 Pressure Relief Valve Capacity.

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

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

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:

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

For SI units:

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

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)]

Chapter 8 Vaporization Facilities

8.1 Classification of Vaporizers.

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8.1.1 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 remotely heated vaporizer.

8.1.2 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.

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8.2 Design and Materials of Construction.

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

8.2.2 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.

8.3 Vaporizer Piping and Intermediate Fluid Piping and Storage.

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

8.3.2 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)].

8.3.3 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.

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

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

8.3.4 Inlet Valves.

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

8.3.4.2 The LNG or gas that can accumulate between the valves or other double block and bleed systems shall be piped to an area with no ignition sources and where people are not present.

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

8.3.5.1 Where the 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.

8.3.5.2 Where the vaporizer is located less than 50 ft (15 m) from the heat source, it shall have an automatic shutoff valve in the liquid line located at least 10 ft (3 m) from the vaporizer and shall close when any of the following occurs:

(1) Loss of line pressure (excess flow)

(2) Abnormal temperature sensed in the immediate vicinity of the vaporizer (fire)

(3) Low temperature in the vaporizer discharge line

8.3.5.3 If the facility is attended, operation of the automatic shutoff valve shall be either from a point at least 50 ft (15 m) from the vaporizer or in accordance with 8.3.5.1.

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

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

(B) This valve shall be either the container shutoff valve or another valve.

8.3.7 Any ambient vaporizer or a heated vaporizer installed within 50 ft (15 m) of an LNG container shall be equipped with an automatic shutoff valve in the liquid line.

(A) The automatic shutoff valve shall be located at least 10 ft (3 m) from the vaporizer and shall close in one of the following situations:

(1) Loss of line pressure (excess flow) occurs

(2) Abnormal temperature sensed in the immediate vicinity of the vaporizer (fire)

(3) Low temperature in the vaporizer discharge line

(B) If the facility is attended, operation of the automatic shutoff valve shall be from a point at least 50 ft (15 m) from the vaporizer or in accordance with 8.3.7(A).

8.3.8 Where a flammable intermediate fluid is used with a remote heated 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.

8.4 Relief Devices on Vaporizers.

8.4.1 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.

8.4.2 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.

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

8.5 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.

8.6 Products of Combustion.

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

Chapter 9 Piping Systems and Components

9.1 General.

9.1.1 All piping systems shall be in accordance with ASME B 31.3, *Process Piping*.

9.1.1.1 The additional provisions of this chapter shall apply to piping systems and components for flammable liquids and flammable gases.

9.1.1.2 Fuel gas systems shall be in accordance with NFPA 54, *National Fuel Gas Code*, or ASME B 31.3, *Process Piping*.

9.1.2 The seismic ground motion used in the piping design shall be the operating basis earthquake (OBE). *(See 7.2.2.4.)*

9.1.2.1 The piping loads shall be determined by a dynamic analysis or by applying an amplification factor of 0.60 to the maximum design spectral acceleration, S_{DS}, as defined in 7.2.3.1.

9.1.2.2 Container-associated piping up to and including the first container shutoff valve in LNG lines shall be designed to isolate the LNG container and maintain it in a safe shutdown condition.

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

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

9.2 Materials of Construction.

9.2.1 General.

9.2.1.1 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.

9.2.1.2 Piping 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

9.2.1.3 Piping insulation used in areas where the mitigation of fire exposure is necessary shall be made of material(s) that cannot propagate fire in the installed condition and shall maintain any properties that are necessary during an emergency when exposed to fire, heat, cold, or water.

9.2.2 Piping.

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

9.2.2.2 Where longitudinal welded or spiral welded pipe is used, the weld and the heat-affected zone shall comply with Section 323.2.2 of ASME B 31.3, *Process Piping*.

9.2.2.3 Threaded pipe shall be at least Schedule 80.

9.2.2.4 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).

9.2.2.5 Transition Joints.

(A) Transition joints shall be protected against fire exposure.

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

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

9.2.3 Fittings.

9.2.3.1 Threaded nipples shall be at least Schedule 80.

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

9.2.3.3 Bends.

(A) Bends shall be permitted only in accordance with ASME B 31.3, *Process Piping*, Section 332.

(B) Field bending shall not be allowed on any 300 series stainless steel or other cryogenic containment component, except instrument tubing.

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

9.2.3.5 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, *Process Piping*, Section 315.

9.2.4 Valves.

9.2.4.1 In addition to complying with ASME B 31.3, *Process Piping*, Section 307, valves shall comply with ASME B 31.5, *Refrigeration Piping*; ASME B 31.8, *Gas Transmission*

and Distribution Piping Systems; or API 6D, *Specification for Pipeline Valves*, if design conditions fall within the scope of those standards.

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

9.3 Installation.

9.3.1 Piping Joints.

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

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

9.3.1.3 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.

9.3.1.4 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.

9.3.1.5 Where threaded joints are used, they shall be seal welded or sealed by other means proven by test.

9.3.1.6 Copper, copper alloys, and stainless steel in cryogenic service shall be joined by silver brazing.

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

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

9.3.2 Valves.

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

9.3.2.2 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.

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

(1) Shutoff valves at connections for relief valves in accordance with the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1, UG-125(d) and Appendix M, M-5 and M-6

(2) Connections for liquid level alarms as required by 10.1.1.3

(3) Connections that are blind flanged or plugged

9.3.2.4 Shutoff valves shall be located inside the impoundment area as close as practical to

such containers, tanks, and vessels where provided.

9.3.2.5 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.

9.3.2.6 In addition to the container shutoff valve required in 9.3.2.2, 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

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

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

9.3.3 Welding.

9.3.3.1 Qualification and performance of welders shall be in accordance with Section 328.2 of ASME B 31.3, *Process Piping*, and 9.3.3.2 of this standard.

9.3.3.2 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.

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

9.3.3.4 Oxygen–fuel gas welding shall not be permitted.

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

(1) Markings shall be made with a material compatible with the pipe material, such as chalk, wax-base crayons, or marking inks with organic coloring or with a round-bottom, low-stress die.

(2)* Materials less than ¼ in. (6.35 mm) in thickness shall not be die stamped.

(3) Marking materials that are corrosive to the pipe material shall not be used.

9.4 Pipe Supports.

9.4.1 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.

9.4.2 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.

9.4.3 The design of supporting elements shall conform to ASME B 31.3, *Process Piping*, Section 321.

9.5* Piping Identification.

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

9.6 Inspection and Testing of Piping.

9.6.1 Pressure Testing.

9.6.1.1 Pressure tests shall be conducted in accordance with ASME B 31.3, *Process Piping*, Section 345.

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

9.6.2 Record Keeping.

9.6.2.1 Records of pressure, test medium temperature, and ambient temperature shall be maintained for the duration of each test.

9.6.2.2 The records shall be maintained for the life of the facility or until such time as a retest is conducted.

9.6.3 Welded Pipe Tests.

9.6.3.1 Longitudinal welded pipe that is subjected to service temperatures below -20°F (-29°C) shall meet one of the following requirements:

(1) It shall have a design pressure of less than two-thirds the mill proof test pressure or subsequent shop.

(2) It shall be hydrostatically tested pressure.

9.6.3.2 All circumferential butt welds shall be examined fully by radiographic or ultrasonic inspection.

(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, *Process Piping*, Section 344.2.

(B) Pressure piping operating above -20°F (-29°C) shall have 30 percent of each day's circumferentially welded pipe joints nondestructively tested over the entire circumference, in accordance with ASME B 31.3.

9.6.3.3 All socket welds and fillet welds shall be examined fully by liquid penetrant or magnetic particle inspection.

9.6.3.4 All fully penetrated groove welds for branch connections, as required by ASME B 31.3, *Process Piping*, Section 328.5.4, shall be fully examined by one of the following methods:

(1) By in-process examination in accordance with ASME B 31.3, Section 344.7 and by liquid penetrant or magnetic particle techniques after the final pass of the weld

(2) By radiographic or ultrasonic techniques where specified in the engineering design or specifically authorized by the inspector

9.6.4 Inspection Criteria.

9.6.4.1 Nondestructive examination methods, limitations on defects, the qualifications of the authorized inspector, and the personnel performing the examination shall meet the requirements of ASME B 31.3, *Process Piping*, Sections 340 and 344.

9.6.4.2 Substitution of in-process examination for radiography or ultrasonics as permitted in ASME B 31.3, *Process Piping*, Paragraph 341.4.1 shall be prohibited.

9.6.5 Record Retention.

9.6.5.1 Test records and written procedures required when conducting nondestructive examinations shall be maintained for the life of the piping system or until such time as a re-examination is conducted.

9.6.5.2 Records and certifications pertaining to materials, components, and heat treatment as required by ASME B 31.3, *Process Piping*, subparagraphs 341.4.1(c) and 341.4.3(d) and Section 346 shall be maintained for the life of the system.

9.7 Purging of Piping Systems.

9.7.1* Systems shall be purged of air or gas.

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

9.8 Safety and Relief Valves.

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

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

9.8.3 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.

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

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

9.9 Corrosion Control.

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

9.9.2 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.

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

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

Chapter 10 Instrumentation and Electrical Services

10.1 Liquid Level Gauging.

10.1.1 LNG Containers.

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

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

10.1.1.3 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 10.1.1.3 shall not be considered as a substitute for the alarm.

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

10.1.2 Tanks for Refrigerants or Flammable Process Fluids.

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

10.1.2.2 If it is possible to overfill the tank, a high-liquid-level alarm shall be provided in accordance with 10.1.1.3.

10.1.2.3 The requirements of 10.1.1.3 shall apply to installations of flammable refrigerants.

10.2 Pressure Gauging.

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

10.3 Vacuum Gauging.

Vacuum-jacketed equipment shall be equipped with instruments or connections for checking

the absolute pressure in the annular space.

10.4 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.

10.4.1 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.

10.4.2 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.

10.5 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 failsafe condition that is maintained until the operators can take action either to reactivate or to secure the system.

10.6 Electrical Equipment.

10.6.1 Electrical equipment and wiring shall be in accordance with NFPA 70, *National Electrical Code*, or CSA C22.1, *Canadian Electrical Code*, for hazardous locations.

10.6.2* Fixed electrical equipment and wiring installed within the classified areas specified in Table 10.6.2 shall comply with Table 10.6.2 and Figure 10.6.2 and shall be installed in accordance with NFPA 70, *National Electrical Code*, for hazardous locations.

Table 10.6.2 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 excee distance between dike and container walls *[. Figure A.10.6.2(b).]*
		2	Within 15 ft (4.5 m) in all directions from c walls and roof plus area inside a low-type di impounding area up to the height of the dik impoundment wall *[See Figure A.10.6.2(a).*
	Outdoor belowground containers	1	Within any open space between container w surrounding grade or dike *[See Figure A.10*

Table 10.6.2 Electrical Area Classification

Part	Location	Group D, Division[a]	Extent of Classified Area
		2	Within 15 ft (4.5 m) in all directions from r sides *[See Figure A.10.6.2(c).]*
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 sepa a gastight partition and 15 ft (4.5 m) beyond wall or roof ventilation discharge vent or lou
	Outdoors in open air at or above grade	2	Within 15 ft (4.5 m) in all directions from tl equipment and within the cylindrical volum between the horizontal equator of the sphere grade *[See Figure 10.6.2.]*
D	**Pits, trenches, or sumps located in or adjacent to Division 1 or 2 areas**	1	Entire pit, trench, or sump
E	**Discharge from relief valves**	1	Within direct path of relief valve discharge
F	**Operational bleeds, drips, vents, or drains**		
	Indoors with adequate ventilation[c]	1	Within 5 ft (1.5 m) in all directions from po discharge
		2	Beyond 5 ft (1.5 m) and entire room and 15 m) beyond any wall or roof ventilation disch vent or louver
	Outdoors in open air at or above grade	1	Within 5 ft (1.5 m) in all directions from po discharge
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) 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 co regularly made or disconnected for product
		2	Beyond 5 ft (1.5 m) and entire room and 15 m) beyond any wall or roof ventilation disch vent or louver
	Outdoors in open air at or above grade	1	Within 5 ft (1.5 m) in all directions from co regularly made or disconnected for product
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) directions from a point where connections a regularly made or disconnected and within t cylindrical volume between the horizontal e the sphere and grade *[See Figure 10.6.2.]*

Table 10.6.2 Electrical Area Classification

Part	Location	Group D, Division[a]	Extent of Classified Area
H	**Electrical seals and vents specified in 10.6.4 and 10.6.5**	2	Within 15 ft (4.5 m) in all directions from tl equipment and within the cylindrical volum between the horizontal equator of the sphere grade

[a]See Article 500 in NFPA 70, *National Electrical Code*, for definitions of classes, groups, and divisions. Most flammable vapors and gases found within the facilities covered by NFPA 59A are classified as Group D. Ethyl classified as Group C. Much available electrical equipment for hazardous locations is suitable for both groups.
[b]Small containers are those that 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.

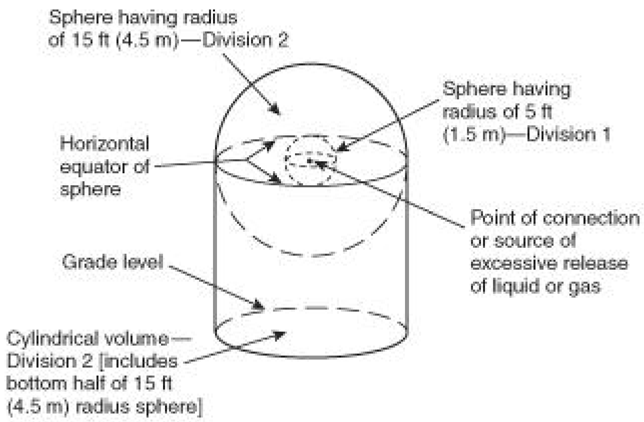

FIGURE 10.6.2 Extent of Classified Area Around Containers.

10.6.3 Electrically classified areas shall be as specified in Table 10.6.2.

(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 10.6.2.

10.6.4 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.

10.6.5 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.

10.6.5.1 Each seal, barrier, or other means used to comply with 10.6.4 shall be designed to prevent the passage of flammable fluids through the conduit, stranded conductors, and cables.

10.6.5.2 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.

10.6.5.3 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 10.6.5.3(A) shall be made on double-integrity primary sealant systems of the type used for submerged motor pumps.

(C) The requirements of 10.6.5.3(A) shall apply to double-integrity primary sealant systems.

10.6.5.4 The seals specified in 10.6.4, 10.6.5, and 10.6.6 shall not be used to meet the sealing requirements of NFPA 70, *National Electrical Code*, or CSA C 22.1, *Canadian Electrical Code.*

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

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

10.7 Electrical Grounding and Bonding.

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

10.7.2 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.

10.7.3* 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.

10.7.4* Lightning protection shall not be required on LNG storage containers, except that lightning protection ground rods shall be provided for tanks supported on nonconductive foundations.

Chapter 11 Transfer of LNG and Refrigerants

11.1 Scope.

This chapter applies to 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 At least one qualified person shall be in constant attendance while a transfer is in progress.

11.2.2 Sources of ignition, such as welding, flames, and unclassified electrical equipment, shall not be permitted in loading or unloading areas while transfer is in progress.

11.2.3 Loading and unloading areas shall be posted with signs that read "No Smoking."

11.2.4 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.

11.3 Piping System.

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

11.3.2* Closure Time.

11.3.2.1 Where power-operated isolation valves are installed, the closure time shall not produce a hydraulic shock capable of causing line or equipment failure.

11.3.2.2 The closing shall not cause pipe stresses that can result in pipe failure.

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

11.3.4 Check valves shall be installed in 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.

11.4 Purging.

11.4.1 The temperature of the purge gas or liquid shall be at or above the minimum design

temperature of the container.

11.4.2 Piping systems shall be purged of air or gas in a safe manner. *(See Section 9.7.)*

11.4.3* Container Purging Procedures.

11.4.3.1 Only experienced, trained personnel shall purge LNG containers.

11.4.3.2 Before an LNG container is put into service, the air shall be displaced by an inert gas, following a written purging procedure.

11.4.3.3* Before a container is taken out of service, the natural gas in the container shall be purged from the container with an inert gas, using a written purging method.

11.4.3.4 During purging operations, the oxygen content of the container shall be monitored by the use of an oxygen analyzer.

11.5 Pump and Compressor Control.

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

11.5.2 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.

11.5.3 Controls located aboard a marine vessel shall meet the requirement in 11.5.2.

11.5.4 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.

11.6 Marine Shipping and Receiving.

11.6.1 Each facility that handles LNG shall develop a contingency plan to address potential incidents that can occur in or near the transfer area and shall include 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

11.6.2 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

(13) Number, location, and load capacity of mooring hooks and mooring line characteristics

(14) Arrangements for ship and shore emergency shutdown systems

11.6.3 The requirements of 11.6.1 shall be communicated to the vessel operator to facilitate safe vessel berthing and unberthing.

11.6.4 Mooring Plans.

11.6.4.1 A vessel-specific mooring plan shall be developed for each ship calling at the waterfront facility utilizing the criteria developed in 11.6.2.

11.6.4.2 Mooring plans shall be available for inspection at the dock area.

11.6.5 The vessel shall be moored in a safe and effective manner.

11.6.6 Sources of ignition, such as welding, flames, and unclassified electrical equipment, shall not be permitted in the marine transfer area while transfer is in progress.

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

11.6.8 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 of transfer connection while LNG or flammable fluids are being transferred through piping systems.

11.6.9 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.

11.6.10 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.

11.6.11 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.

11.6.12 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 pier or dock.

(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.

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

11.6.14 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.

11.6.15 Transfer Operations.

11.6.15.1 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.

11.6.15.2 Each person involved in the shoreside transfer operations shall have been trained in accordance with the requirements of Section 4.2 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

11.6.16 Certification.

11.6.16.1 The terminal operator shall certify in writing that the provisions of 11.6.15 are

met before transfer of LNG begins.

11.6.16.2 This certification shall be available for inspection at the waterfront facility handling LNG.

11.6.17 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 there are no ignition sources 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

11.6.18 After the pretransfer inspection required by 11.6.17 has been satisfactorily completed, there shall be no transfer of LNG until a declaration of inspection that demonstrates full compliance with 11.6.17 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 at the waterfront facility handling LNG for 30 days after completion of the transfer.

(B) Each declaration of inspection shall contain the following:

(1) The name of the vessel and the waterfront facility handling 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

11.6.19* Each marine LNG transfer system shall have an emergency shutdown (ESD) system that does the following:

(1) Can be activated manually

(2) Provides for the orderly shutdown of LNG transfer components

11.6.20* There shall be two independent means of egress, including emergency egress, from the ship.

11.6.21 During transfer of a ship's stores, including nitrogen, the following shall apply:

(1) Personnel involved in the transfer of a ship's stores shall not have simultaneous responsibility involved in the transfer of LNG

(2) No vessels shall be moored alongside the LNG vessel without the permission of the facility operator

11.6.22 Bunkering Operations.

11.6.22.1 Bunkering operations shall be in accordance with any requirements established by the agency having jurisdiction over vessels or terminals.

11.6.22.2 During bunkering operations, the following shall apply:

(1) Personnel involved in bunkering operations shall not have simultaneous responsibility involved in the transfer of LNG.

(2) No vessels shall be moored alongside the LNG vessel without the permission of the authority having jurisdiction.

(3) The person in charge of bunkering operations on the bunkering vessel shall be in continuous communication with the person in charge of bunkering operations on the LNG vessel.

11.7 Tank Vehicle and Tank Car Loading and Unloading Facilities.

11.7.1 Transfer shall be made only into tank cars approved for LNG service.

11.7.2 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, *Liquefied Petroleum Gas Code*.

(3) Flammable liquid tank vehicles shall comply with NFPA 385, *Standard for Tank Vehicles for Flammable and Combustible Liquids*.

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

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

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

11.7.6 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.

11.7.7 Bleeds or vents shall discharge to a safe area.

11.7.8 In addition to the isolation valving at the manifold, an emergency 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.

11.7.8.1 Emergency valves shall be readily accessible for emergency use.

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

11.7.8.3 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.

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

11.8 Pipeline Shipping and Receiving.

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

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

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

11.8.4 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.

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

11.8.6 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.

11.9 Hoses and Arms.

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

11.9.2 Hoses shall be approved for the service and shall be designed for a bursting pressure of not less than five times the working pressure.

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

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

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

11.9.6 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.

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

11.9.8 Flanges.

11.9.8.1 When loading arms are connected for marine loading or unloading operations, all bolt holes in a flange shall be utilized for the connection.

11.9.8.2 Blind flanges shall be utilized on those arms not engaged in loading or unloading operations.

11.9.9 Marine loading or unloading operations shall be purged prior to use and purged and completely drained upon completion of transfer.

11.9.10 Marine loading or unloading operations shall be at ambient pressure when connecting or disconnecting the arm(s).

11.10 Communications and Lighting.

11.10.1 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.

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

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

11.10.4 The communication system required in 11.10.3 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.

12.2.2 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) Fire protection water systems

(5) 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 protective equipment, special training, and qualification needed by individual plant personnel as specified by NFPA 600, *Standard on Industrial Fire Brigades*, for their respective emergency duties

(10) Other fire protection equipment and systems

12.3 Emergency Shutdown 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 Where valves and equipment are installed based on other requirements of this standard, and a valve or equipment is required for an emergency shutdown system, duplicate valves and equipment shall not be required.

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 failsafe design or shall be otherwise installed, located, or protected to minimize the possibility that it becomes 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 failsafe design shall have all components that are located within 50 ft (15 m) of the equipment to be 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 Fire and Leak Detection.

12.4.1 Areas, including enclosed buildings, that can have flammable gas present, 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 low-temperature sensors or 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 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 The detection systems shall be designed, installed, and maintained in accordance with *NFPA 72*, *National Fire Alarm Code*.

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 not less than 2 hours.

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, *Standard for Portable Fire Extinguishers*.

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, *Standard for Automotive Fire Apparatus*.

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.

Facility 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 facility.

12.8.2 Employees who are involved in emergency response activities shall be equipped with protective clothing and equipment and trained in accordance with NFPA 600, *Standard on Industrial Fire Brigades*.

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 facility.

12.9.1.2 The security assessment shall be available to the authority having jurisdiction on a nonpublic basis.

12.9.2 The facility operator shall provide a security system with controlled access that is designed to prevent entry by unauthorized persons.

12.9.3 At LNG facilities, 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 facility shall be enclosed either by a single continuous enclosure or by multiple independent enclosures.

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 facilities shall be illuminated in the vicinity of protective enclosures and in other areas as necessary to promote security of the facility.

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 installations using containers of 100,000 U.S. gal (379 m^3) capacity and less constructed in accordance with the ASME *Boiler and Pressure Vessel Code* for vehicle

fueling and commercial and industrial applications.

13.1.2 The maximum aggregate storage capacity shall be 280,000 U.S. gal (1060 m^3).

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 equipment shall be competent in the design, fabrication, and construction of LNG containers, cryogenic equipment, piping systems, fire protection equipment, and other components of the facility.

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.

13.2.9 The maximum aggregate storage capacity shall be 280,000 gal (1060 m^3).

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 other 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 (100 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 (100 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 (0.0034 cm^2/kg) of the water capacity of the inner tank, but the area shall not exceed 300 in.^{2} (2000 cm^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:

$$V = Z_c \times W$$

For vertical force:

$$P = 2/3 Z_c \times W$$

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 0.6 or greater, 7.2.2.1 and 7.2.2.2 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 identified.

13.4 Container Filling.

Containers designed to operate at a pressure in excess of 15 psi (100 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, Building Construction and Safety Code*.

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.

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) to a property line that can be built upon and between containers shall be in accordance with Table 13.6.2.1.

Table 13.6.2.1 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 B Storage Containe	
gal	m^3	ft	m	ft	
1000–2000	3.8–7.6	15	4.6	5	1
2001–18,000	≥7.6–56.8	25	7.6	5	1
18,001–30,000	≥56.8–114	50	15	5	1
30,001–70,000	≥114–265	75	23	¼ of the sum of the dian adjacent containers [5 ft minimum]	
>70,000	>265	0.7 times the container diameter [100 ft (30 m) minimum]			

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.

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 Conta	
gal	**m^3**	**ft**	**m**	**ft**	**n**
<18,000	<15.8	15	4.6	15	4.
18,000–30,000	15.8–114	25	7.6	15	4.
30,001–100,000	>114	40	12.2	15	4.

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 Points of 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 failsafe product retention valves.

13.7.2 Automatic 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 a 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 not 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.

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 Container piping shall be tested in accordance with ASME B 31.3, *Process Piping.*

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, *Process Piping*, 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 *Boiler and Pressure Vessel Code*, Section IX.

(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, *Process Piping*, 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 inspection 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 failsafe 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) 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) 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 7.8.5 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 7.8.5.

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 Detectors.

An operating 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 facility shall meet the following requirements:

(1) Have written procedures covering operation, maintenance, and training

(2) Keep up-to-date drawings of plant 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 as part of the operations manual

(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 plant 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 facility shall have a written manual of emergency procedures included in the operations manual that shall include the types of emergencies that are anticipated from an operating malfunction, structural collapse of part of the facility, personnel error, forces of nature, and activities carried on adjacent to the 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 of 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 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

facility

(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 facility

(2) Potential hazards at the facility

(3) Communication and emergency control capabilities of the facility

(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 facility operator shall carry out periodic inspection, tests, or both as required on every component and its support system in service in the facility, to verify that the component is 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 facility 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 the equivalent thereto, 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 each component that is 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 facility 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*, *National Fire Alarm Code*, and NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems*.

(2) Fire protection water systems, if required, shall be maintained in accordance with

NFPA 13, *Standard for the Installation of Sprinkler Systems*; NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*; NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*; NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*; NFPA 22, *Standard for Water Tanks for Private Fire Protection*; and NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*.

(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, *Standard for Portable Fire Extinguishers*.

(4) Fixed fire extinguishers and other fire-control systems that are installed shall be maintained in accordance with NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*; NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*; NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*; NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*; and NFPA 17, *Standard for Dry Chemical Extinguishing Systems*.

(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 plants 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 plant is intact.

13.18.4.6 Each facility operator shall ensure that the requirements of Section 14.11 are met, if applicable.

13.18.4.7 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 as long as the facility is in service.

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 13.18.4

(d) The LNG transfer procedures required in 13.18.4

(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) Recognizing situations in which it is necessary to obtain assistance in order to maintain the security of the facility

13.18.5.2 Each facility operator shall develop, implement, and maintain a written plan to keep the personnel at the facility up to date on the function of the systems, fire prevention, and security at the 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 two 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 Section 13.18.

(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 LNG plant shall have a documented operating manual that includes operations, maintenance, training procedures, cooldown, purging, and record keeping, based on experience and conditions under which the LNG plant is operated, and a documented maintenance manual.

14.2.2 The operating manual shall include the following:

(1) Documented procedures covering operation, maintenance, and training

(2) Up-to-date drawings, charts, and records of plant equipment

(3) Plans and procedures that are revised when operating conditions or plant equipment are revised

(4) A documented emergency plan

(5) Liaison with local authorities such as police, fire department, or municipal works to inform them of the emergency plans and their role in emergency situations

(6)* Analysis and documentation of 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 plant components shall be operated in accordance with the operating procedures manual.

14.3.2 The operating procedures manual shall be accessible to all plant 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.

14.4 Operating Manual Contents.

14.4.1 The operating manual shall include procedures for the proper startup and shutdown of all components of the plant, including those for initial startup of the LNG plant, to ensure that all components operate satisfactorily.

14.4.2 The operating manual shall include procedures for purging components, making components inert, and cooldown of components.

14.4.2.1 Procedures shall ensure that the cooldown of each system of components 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.

14.4.2.2 Each cryogenic piping system shall be checked during and after cooldown stabilization for leaks in flanges, valves, and seals.

14.4.3 The operating manual shall include procedures to ensure that each control system is

adjusted to operate within its design limits.

14.4.4 The operating manual of LNG plants with liquefaction facilities shall include procedures to maintain the temperatures, levels, pressures, pressure differentials, and flow rates 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, within their design limits

14.4.5 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 of the abnormal conditions in 14.4.6 and the response to those conditions in the plant

(3) The safe transfer of LNG and hazardous fluids, including prevention of overfilling of containers

(4) Security

14.4.6 The operations manual shall include procedures for monitoring operations.

14.4.6.1* Operations monitoring shall be carried out by the watching or listening for warning alarms from an attended control center and by inspections conducted at least at the intervals set out in the written operating procedures referred to in Section 14.2 and, at a minimum, on a weekly basis.

14.4.6.2 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.

14.4.6.3 Any settlement in excess of that anticipated in the design shall be investigated and corrective action taken as required.

14.4.7 Inspection Records.

14.4.7.1 Each LNG plant shall maintain a record of each inspection, test, and investigation required by the operations manual.

14.4.7.2 Records of inspections, tests, and investigations shall be retained for at least 5 years.

14.4.8 Each operations manual shall contain emergency procedures.

14.4.8.1 The emergency procedures shall include, at a minimum, emergencies that are anticipated from an operating malfunction, structural collapse of part of the LNG plant,

personnel error, forces of nature, and activities carried on adjacent to the plant.

14.4.8.2 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

14.4.8.3 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

14.4.8.4 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

14.4.8.5 Normally, gas fires (including LNG) should not be extinguished until the fuel source has been shut off, unless the fire would create more of a hazard than the gas dispersion.

14.4.8.6 Each operating company shall ensure that components in its LNG plant that could accumulate combustible mixtures are purged after being taken out of service and before being returned to service.

14.5 Maintenance Manual.

14.5.1 Each LNG facility shall have a written manual that sets out an inspection and maintenance program for each component used in its LNG plant.

14.5.2 The maintenance manual shall include maintenance procedures, including procedures for the safety of personnel and property while repairs are carried out, whether or not the equipment is in operation.

14.5.3 The maintenance manual shall include the following for LNG plant 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 14.5.3(1), that is

necessary to maintain the LNG plant 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

14.5.4 Each maintenance program shall be conducted in accordance with its written manual for LNG plant components.

14.5.5 Each periodic inspection, tests, or both, shall be conducted on a schedule that is included in the maintenance manual on every component and its support system that is in service in its LNG plant.

14.5.6 Foundation.

14.5.6.1 The support system or foundation of each component shall be inspected at least annually.

14.5.6.2 If the foundation is found to be incapable of supporting the component, it shall be repaired.

14.5.7 Each emergency power source at the LNG plant shall be tested monthly to ensure that it is operational and annually to ensure that it is capable of performing at its design capacity, including power needed to operate all plant equipment needed in a power outage.

14.5.8 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.

14.5.9 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 thereto, shall be attached to the controls of the component, or the component shall be locked out.

14.5.10 Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open.

14.5.10.1 Stop valves shall not be operated except by an authorized person.

14.5.10.2 No more than one stop valve shall be closed at one time.

14.5.11 Insulation systems for impounding surfaces shall be inspected annually.

14.6 Marine Shipping and Receiving.

14.6.1* Transfer Operations in Progress.

14.6.1.1 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.

14.6.1.2 Warning signs or barricades shall be used to indicate that transfer operations are in progress.

14.6.2 Prior to Transfer.

14.6.2.1 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 the proper operating condition.

14.6.2.2 Following the inspection described in 14.6.2.1, 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.

14.7 Product Transfer.

14.7.1 Where bulk transfers are made into stationary storage containers, the LNG being transferred shall be compatible in composition or temperature and density with the LNG already in the container.

14.7.2 Where the composition or temperature and density are not compatible, means shall be taken to prevent stratification and vapor evolution that could cause rollover.

14.7.3 Where a mixing nozzle or agitation system is provided, it shall be designed to prevent rollover.

14.8 Loading or Unloading Operations.

14.8.1 General Requirements.

14.8.1.1* At least one qualified person shall be in constant attendance while loading or unloading is in progress.

14.8.1.2 Written Procedures.

(A) Written procedures shall be available to cover all transfer operations and shall cover emergency as well as normal operating procedures.

(B) Written procedures shall be kept up to date and available to all personnel engaged in transfer operations.

14.8.1.3 Sources of ignition, such as welding, flames, and unclassified electrical equipment, shall not be allowed in loading or unloading areas while transfer is in progress.

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

14.8.1.5 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.

14.8.1.6 Prior to transfer, gauge readings shall be obtained or inventory established to ensure that the receiving vessel cannot be overfilled, and levels shall be checked during transfer operations.

14.8.1.7 The transfer system shall be checked prior to use to ensure that valves are in the correct position, and pressure and temperature conditions shall be observed during the transfer operation.

14.8.1.8 The transfer system shall be checked prior to use to ensure that valves are in the correct position for transfer.

14.8.1.9 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.

14.8.1.10 Pressure and temperature conditions shall be monitored during the transfer operation.

14.8.2 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.

14.8.2.1 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.

14.8.2.2 The warning signs or lights shall not be removed or reset until the transfer is completed and the car disconnected.

14.8.2.3 Truck vehicle engines shall be shut off if not required for transfer operations.

14.8.2.4 Brakes shall be set and wheels checked prior to connecting for unloading or loading.

14.8.2.5 The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.

14.8.2.6 Oxygen Content.

(A) 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.

(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.

14.8.2.7 No Positive Pressure.

(A) If a tank car or tank vehicle in exclusive LNG service does not contain a positive pressure, it shall be tested for oxygen content.

(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.

14.8.2.8 Prior to loading or unloading, a tank vehicle shall be positioned so it can exit the area without backing up when the transfer operation is complete.

14.8.2.9 Tank cars and tank vehicles that are top-loaded through an open dome shall be bonded electrically to the fill piping or grounded prior to opening the dome.

14.8.3 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.

14.9 Other Operations.

14.9.1 The discharge from depressurizing shall be directed to minimize exposure to

personnel or equipment.

14.9.2 Taking an LNG container out of service shall not be regarded as a normal operation.

14.9.3 All such activities shall require the preparation of detailed procedures.

14.10 Site Housekeeping.

14.10.1 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 plant 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

14.10.2 Repairs that are carried out on components of an LNG plant 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

14.11 Control Systems, Inspection, and Testing.

14.11.1 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.

14.11.2 Each operating company shall ensure that the inspections and tests in this section are carried out at the intervals specified.

14.11.3 Control systems that are used seasonally shall be inspected and tested before use each season.

14.11.4 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 code and conform to the following:

(1) Monitoring equipment shall be maintained in accordance with *NFPA 72*, *National Fire Alarm Code*, and NFPA 1221, *Standard for the Installation, Maintenance, and Use of Emergency Services Communications Systems*.

(2) Fire protection water systems shall be maintained in accordance with NFPA 13, *Standard for the Installation of Sprinkler Systems*; NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*; NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*; NFPA 20, *Standard for the Installation of*

Stationary Pumps for Fire Protection; NFPA 22, *Standard for Water Tanks for Private Fire Protection*; and NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*.

(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, *Standard for Portable Fire Extinguishers*.

(4) Fixed fire extinguishers and other fire control equipment shall be maintained in accordance with NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*; NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*; NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*; NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*; NFPA 17, *Standard for Dry Chemical Extinguishing Systems*; and NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*.

14.11.5 Control systems, other than those referred to in 14.11.3 and 14.11.4, shall be inspected and tested once each calendar year at intervals that do not exceed 15 months.

14.11.6 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.

14.11.7 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.

14.11.8 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

14.11.9 LNG storage plants 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 plant is intact.

14.11.10 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.

14.12 Corrosion Control.

14.12.1 Each operating company shall ensure the following for metallic components of its

LNG plant 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 9.9

(2) Inspection and replacement or repair under a program of scheduled maintenance in accordance with the manual referred to under Section 14.4

14.12.2 Each operating company shall ensure that each component of its LNG plant that is subject to interference from an electrical current is protected so that the electrical interference is minimized.

14.12.3 Each impressed current power source shall be so installed and maintained that it does not interfere with any communication or control system at the LNG plant.

14.12.4* Every operating company shall monitor the corrosion control provided under Section 9.9.

14.12.4.1 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.

14.12.4.2 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.

14.12.4.3 Interference bonds shall be inspected at least once each calendar year at intervals that do not exceed 15 months.

14.12.4.4 Each exposed component that is subject to corrosion from the atmosphere shall be inspected at intervals that do not exceed 3 years.

14.12.4.5 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.

14.12.4.6 Internal corrosion control monitoring devices shall be checked at least two times each calendar year at intervals not exceeding 7½ months.

14.12.5 Components that will not be adversely affected by internal corrosion during the time that the component will be in use in the LNG plant shall be exempt from the requirements of Section 14.12.

14.12.6 If it is discovered by inspection or otherwise that corrosion is not being controlled at the LNG plant, necessary actions to control or monitor the corrosion shall be taken.

14.13 Records.

14.13.1 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 plant, including a record of the date that a component is taken out of or placed into service.

14.13.2 Records shall be made available during business hours upon reasonable notice.

14.13.3 Each LNG plant operator shall maintain records of each test, survey, or inspection required by this standard in sufficient detail to demonstrate the adequacy of corrosion control measures for the life of the LNG facility.

14.14 Personnel Training.

14.14.1 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 11.6.1

14.14.1.1 Time spent assisting in the transfer shall fulfill this practical training requirement.

14.14.2 Refresher Training.

14.14.2.1 Personnel who received the training required by 11.6.1 shall receive refresher training in the same subjects at least once every 2 years.

14.14.2.2 Performing actual loading or unloading operations shall fulfill the requirement for refreshing of practical training.

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 constituents are present, see 3.3.15. For information on the use of LNG as a vehicle fuel, see NFPA 52, *Vehicular Fuel Systems Code*.

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.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.3.3.12 G. At sea level, G equals approximately 32.2 ft/sec/sec (9.81 m/sec/sec)

A.3.3.22 Transfer Area. Transfer areas do not include product sampling devices or

permanent plant piping.

A.5.1 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 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 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 facility.

A.5.1.4 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.5.4 The terms *competence* and *competent* in this standard should be determined based on one of the following criteria:

(1) Documented training or certification from institutions or groups that test for knowledge, skill, and ability that relate to the science, technology, or engineering discipline for the facility or component

(2) Evidence of successful design, construction, operation, or use of a similar facility or component

Evidence to be considered should include but not be limited to the following:

(1) Work on similar facilities or components

(2) Date(s) that work was performed and completed

(3) Owner/operator contact information

(4) The amount of time the facility or component has been in operation

(5) Any substantive modifications to the original facility or component

(6) Satisfactory performance of the facility or component

The terms *competence* and *competent* in this standard should also be determined based on the evidence of knowledge, skill, and ability to do the following:

(1) Recognize an abnormal or flawed condition

(2) Respond accordingly to prevent an unsafe or hazardous condition from occurring or to correct such a condition at any stage of the construction or operation of the facility or component

A.5.4.2 See ASCE 56, *Subsurface Investigation for Design and Construction of Foundation for Buildings*, and API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, Appendix C, for further information.

A.5.5 Soil movement due to freezing of water is of two general types, as follows:

(1) The freezing of in situ water causes volumetric expansion of a moist soil.

(2) Frost heave is caused by migration of water to a zone of freezing and a continual growth of ice lenses.

A.5.7.5 Slope protection and impounding area paving are examples of incidental nonstructural concrete use.

A.6.4.4 For information on internal combustion engines or gas turbines exceeding 7500 horsepower per unit, see NFPA 850, *Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations*.

A.7.2.1.4 Operating requirements for prevention of stratification are located at Section 14.7.

A.7.2.2.4 The OBE ground motion need not exceed the motion represented by a 5 percent damped acceleration response spectrum having a 10 percent probability of exceedance within a 50-year period.

A.7.2.7.1 Foundation designs and container installations should account for applicable site-specific conditions, such as flood loads, wind loads, and seismic loads. The *Canadian Foundation Engineering Manual*, published by the Canadian Geotechnical Society; ASCE 56, *Subsurface Investigation for Design and Construction of Foundation for Buildings*; and Appendix C of API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, can be used as guides for the subsurface investigation.

A.7.2.7.4(3) It might not be practical to add a cathodic protection system to an existing tank's outer tank bottom, because of integral electrical conductivity of the bottom to the tank or plant ground and lightning protection system. Grounding can make a cathodic protection system ineffective.

A.7.2.7.5(D) Moisture accumulation in the conduit can lead to galvanic corrosion or other forms of deterioration within the conduit or heating element.

A.7.3.1.2(2) API 620 defines examination as either radiographic or ultrasonic examination.

A.7.8.5.3 For double-wall, perlite-insulated tanks, this can be the governing criterion for pressure relief valve sizing.

A.7.8.7.3 It is the responsibility of the user to determine whether the insulation will resist dislodgment by the available fire-fighting equipment and to determine the rate of heat

transfer through the insulation when exposed to fire.

A.8.2.1 Because these vaporizers operate over a temperature range of -260°F to +100°F (-162°C to +37.7°C), the rules of the ASME *Boiler and Pressure Vessel Code*, Section I, Part PVG are not applicable.

A.9.1.3 Particular consideration should be given where changes in size of wall thickness occur between pipes, fittings, valves, and components.

A.9.3.4(2) Under some conditions, marking materials that contain carbon or heavy metals can corrode aluminum. Marking materials that contain chloride or sulfur compounds can corrode some stainless steels.

A.9.5 For information on identification of piping systems, see ASME A 13.1, *Scheme for the Identification of Piping Systems.*

A.9.7.1 ASME B31.8, *Gas Transmission and Distribution Piping Systems*, paragraph 841.275 can be used as a guide.

A.9.9.1 49 CFR 192, Subpart I, includes corrosion protection requirements.

A.10.6.2 In the classification of the extent of the hazardous area, consideration should be given to possible variations in the spotting of tank cars and tank vehicles at the unloading points and the effect those variations might have on the point of connection.

See Figure A.10.6.2(a) through Figure A.10.6.2(c).

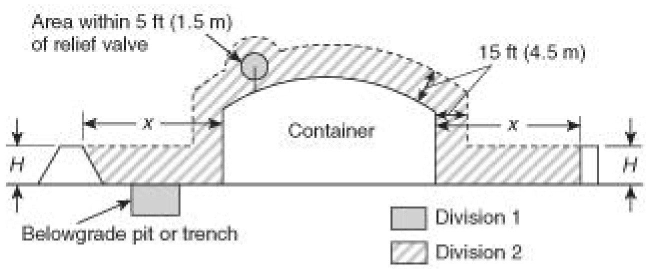

FIGURE A.10.6.2(a) Dike Height Less than Distance from Container to Dike ($H < x$).

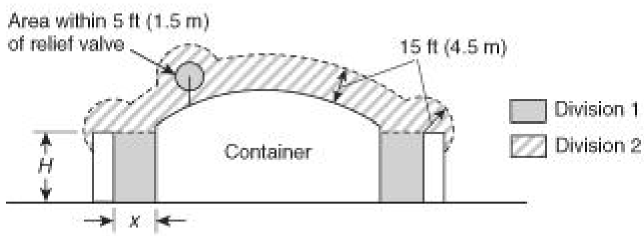

FIGURE A.10.6.2(b) Dike Height Greater than Distance from Container to Dike ($H > x$).

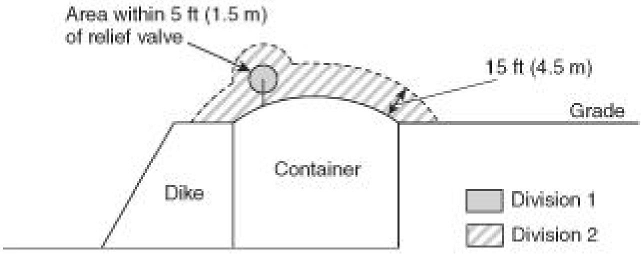

FIGURE A.10.6.2(c) Container with Liquid Level Below Grade or Below Top of Dike.

A.10.7.1 For information on grounding and bonding, see NFPA 77, *Recommended Practice on Static Electricity*, Section 5.4 and 6.1.3, and NFPA 70, *National Electrical Code*.

A.10.7.3 For information on stray currents, see API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents.*

A.10.7.4 For information on lightning protection, see NFPA 780, *Standard for the Installation of Lightning Protection Systems*, and API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents.*

A.11.3.2 If excessive stresses are indicated, an increase of the valve closure time or other methods can be used to reduce the stresses to a safe level.

A.11.4.3 Several methods can be used for purging large containers into and out of service.

Several references cover the purging of large containers. Refer to *Purging, Principles and Practice*, available from the American Gas Association.

A.11.4.3.3 Many insulating materials that have had prolonged exposure to natural gas or methane retain appreciable quantities of the gas within their pores or interstitial spaces.

A.11.6.19 The emergency shutdown system required by 11.6.19 can be part of the facility ESD system, or it can be a separate ESD system specific to transfer operations.

A.11.6.20 The ship's existing lifesaving appliances (i.e., lifeboats) can fulfill the requirement for emergency egress.

A.12.2 For information on fire extinguishing systems, see the following:

(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 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*

(14) NFPA 68, *Guide for Venting of Deflagrations*

(15) NFPA 69, *Standard on Explosion Prevention Systems*

(16) *NFPA 72*, *National Fire Alarm Code*

(17) NFPA 750, *Standard on Water Mist Fire Protection Systems*

(18) NFPA 1961, *Standard on Fire Hose*

(19) NFPA 1962, *Standard for the Inspection, Care, and Use of Fire Hose, Couplings, and Nozzles and the Service Testing of Fire Hose*

(20) NFPA 1963, *Standard for Fire Hose Connections*

(21) NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*

A.12.2.1 The wide range in size, design, and location of LNG facilities covered by this standard precludes the inclusion of detailed fire protection provisions that apply to all facilities comprehensively. Information for the evaluation can be obtained from numerous sources, including NFPA codes, the U.S. Code of Federal Regulations, building codes applicable to the prospective area, and the equipment manufacturer's information.

A.12.2.2(9) Plant fire brigades are not required by this standard. Where the facility elects to have a fire brigade, NFPA 600, *Standard on Industrial Fire Brigades*, is required for protective equipment and training.

A.12.6.1 Extinguishers of the dry chemical type usually are preferred. Fixed fire-extinguishing and other fire control systems can be appropriate for the protection of specific hazards as determined in accordance with 12.2.1.

A.12.8.1 Protective clothing for normal liquid transfer operations should include cryogenic gloves, safety glasses, face shields, and coveralls or long-sleeve shirts.

A.12.8.3 Information concerning confined entry practices and procedures can be found in 29 CFR 1910.146, “Labor”; Canadian Federal Employment and Labor Statutes Part II; and any local, state, or provincial requirements and standards that apply.

A.12.8.4 Natural gas, LNG, and hydrocarbon refrigerants within the process equipment are usually not odorized, and the sense of smell cannot be relied on to detect their presence. Two portable detectors should be available for monitoring when required, with a third detector for

backup. This provides a spare detector in the event of failure of one of the primary detectors and also allows verification if the two primary detectors provide different readings.

A.12.9 Where gas must be released intermittently or in an emergency, a discharge directed upward at high velocity will safely dissipate the gas. Lever-operated relief valves often can be used for this purpose. An ignited flare is permitted in LNG facilities if local conditions warrant.

A.13.6.6 For information on corrosion protection, see NACE RP 0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems.*

A.13.18.3.2 Extinguishment of gaseous fires can cause a build-up of flammable vapors that can result in an explosion causing damage beyond that resulting from the fire itself. Normally the best method for suppression of a gaseous fuel fire is shutoff of the fuel supply, which results in extinguishment of the fire by fuel starvation. In cases where the control equipment is involved in the fire or where damage to equipment or structures will result in loss of control or loss of life, the fire may need to be extinguished. In those cases, vapor control must be implemented immediately to prevent an accumulation of vapors that could result in an explosion.

A.14.1 Because of many variables, it is not possible to describe in a national standard a set of operating and maintenance procedures that will be adequate from the standpoint of safety in all cases without being burdensome or, in some cases, impractical.

A.14.2.2(6) Definitions of safety-related malfunctions are given in 49 CFR 191 for LNG plants under the jurisdiction of the U.S. Department of Transportation under 49 CFR 193.

A.14.4.6.1 If an LNG facility is designed to operate unattended, it is recommended that alarm circuits that can transmit an alarm to the nearest attended company facility be provided to indicate abnormal pressure, temperature, or other symptoms of trouble.

A.14.6.1 For information on operation of piers, docks, and wharves, see NFPA 30, *Flammable and Combustible Liquids Code*.

A.14.8.1.1 Where gas must be released intermittently or in an emergency, a discharge directed upward at high velocity will safely dissipate the gas. Lever-operated relief valves often can be used for this purpose. An ignited flare is permitted in LNG facilities if local conditions warrant.

A.14.12.4 API RP 651, *Cathode Protection of Aboveground Petroleum Storage Tanks*, provides guidance in the use of cathodic protection.

Annex B Seismic Design of LNG Plants

This annex is not a part of the requirements of this NFPA document but is included for informational purposes only.

B.1 Introduction.

The purpose of Annex B is to provide information on the selection and use of operating basis

earthquake (OBE) and safe shutdown earthquake (SSE) seismic levels. These two seismic levels form part of the requirements of this standard for the design of LNG containers, system components required to isolate the container and maintain it in a safe shutdown condition, and any structures or systems the failure of which could affect the integrity of the aforementioned.

When computing lateral forces and shears associated with these two seismic levels, an importance factor, *I*, of 1.0 can be used. That is because, to the extent that the importance factors in ASCE 7, *Minimum Design Loads for Buildings and Other Structures*, and the ICC *International Building Code (IBC)* are identified as "occupancy importance factors" that apply to a broad range of building and structure types, they do not apply to this standard, which deals with a rather narrow, well-defined range of structures (primarily LNG containers and their impounding systems). The designer using this standard should rely on the fact that the "importance" of these structures and their "occupancy category" have already been factored in, as reflected in the definitions of OBE and SSE and the provisions and performance criteria of 7.2.2.

B.2 Operating Basis Earthquake (OBE).

The OBE is a probable earthquake to which a facility can be subjected during its design life. All elements of the facility are designed to withstand this event in accordance with conventional engineering procedures and criteria, and, therefore, the facility is expected to remain in operation.

The OBE is defined as ground motion having a 10 percent probability of exceedance within a 50-year period (mean return interval of 475 years). For design, this motion is typically represented by design response spectra covering the appropriate ranges of natural period and damping ratio.

B.3 Safe Shutdown Earthquake (SSE).

B.3.1 The SSE is the "maximum considered earthquake (MCE) ground motion," per the definition in ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. For most locations, except possibly those near active faults, the MCE is ground motion that has a 2 percent probability of exceedance in a 50-year period. The corresponding design response spectrum is 50 percent greater than the "design earthquake" spectrum as defined in ASCE 7. (The ASCE 7 "design earthquake" represents the ground motion for which buildings are designed so as to safeguard life, although they are allowed to sustain some tolerable damage). In this standard, the LNG facility is designed to contain the LNG and prevent catastrophic failure of critical facilities under an SSE event. Plastic behavior and significant finite movements and deformations are permissible. The facility is not required to remain operational following the SSE event. Following such an event, the facility is expected to be inspected and repaired as necessary. The provisions of this standard are considered equivalent to those applied to an ASCE 7 Seismic Group III structure.

B.3.2 The objective of the selection and use of the SSE is to provide a minimum level of public safety in the event of a very low probability seismic event. It is recognized that the required probability level to achieve acceptable public safety varies from project to project,

depending on such factors as location and population density. It is desirable to allow the owner flexibility in achieving the required level of public safety.

B.3.3 The SSE level of seismic loading is to be used for a limit state check on the specified components. The specified SSE is the minimum level of ground motion that must be used for the analysis. The actual level must be specified by the owner, and when used in conjunction with other considerations, such as location, siting, type of impounding system, hazard control, local climatic conditions, and physical features, it must be sufficient to ensure adequate public safety to the satisfaction of the regulatory authorities. A risk analysis study is recommended. At the SSE level of seismic loading, primary components of the LNG container are permitted to reach the stress limits specified in 7.2.2.7. An LNG container subjected to this level of loading must be capable of continuing to contain a full volume of LNG.

B.3.4 The impounding system must, as a minimum, be designed to withstand the SSE level of loading while empty and the OBE level of loading while holding the volume, V, as specified in 5.2.2.1. The rationale is that should the LNG container fail following an SSE, the impounding system must remain intact and be able to contain the contents of the LNG container when subjected to an aftershock. It is assumed that the strength of the aftershock can be reasonably represented by an OBE.

B.3.5 Systems or components, the failure of which could affect the integrity of the LNG container, the impounding system, or the system components required to isolate the LNG container and maintain it in a safe shutdown condition, must be designed to withstand an SSE.

B.3.6 The operator is required to install instrumentation capable of measuring ground motion at the plant site. Following an earthquake that produces ground motion equal to or greater than the design OBE ground motion, it is advisable that the operator of the facility either take the LNG container out of service and have it inspected or prove that the LNG container components have not been subjected to loading in excess of the container's OBE stress level and design criteria. For instance, if the LNG container was partially full during the seismic event, calculations can prove that the container OBE stress levels were not exceeded.

B.4 Design Response Spectra.

Using the OBE and SSE ground motions as defined in Section B.2 and B.3.1 respectively, vertical and horizontal design response spectra must be constructed that cover 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.

B.5 Other Seismic Loads.

B.5.1 Small LNG plants consisting of shop-built LNG containers and limiting processing equipment should be designed for seismic loading using the ground motion specified by ASCE 7, *Minimum Design Loads for Buildings and Other Structures*. Either a structural response analysis should be performed or an amplification factor of 0.60 should be applied to

the maximum design spectral acceleration (SDS), as defined in 7.2.3.1, to determine the loads on the vessels or piping.

B.5.2 All other structures, buildings, and process equipment must be designed for seismic loading in accordance with ASCE 7, *Minimum Design Loads for Buildings and Other Structures*.

Annex C Security

This annex is not a part of the requirements of this NFPA document but is included for informational purposes only.

C.1 General.

This annex is reprinted from Title 49 of the Code of Federal Regulations, Part 193, Subpart J, Appendix J. The references herein are found in 49 CFR 193. These federal requirements are applicable to LNG plants in the United States under the jurisdiction of the Department of Transportation.

Sec. 193.2901 Scope. This subpart prescribes requirements for security at LNG plants. However, the requirements do not apply to existing LNG plants that do not contain LNG.

Sec. 193.2903 Security procedures. Each operator shall prepare and follow one or more manuals of written procedures to provide security for each LNG plant. The procedures must be available at the plant in accordance with Sec. 193.2017 and include at least:

(1) A description and schedule of security inspections and patrols performed in accordance with Sec. 193.2913;

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

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

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

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

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

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

Sec. 193.2905 Protective enclosures.

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

(a) Storage tanks;

(b) Impounding systems;

(c) Vapor barriers;

(d) Cargo transfer systems;

(e) Process, liquefaction, and vaporization equipment;

(f) Control rooms and stations;

(g) Control systems;

(h) Fire control equipment;

(i) Security communications systems; and

(j) Alternative power sources.
The protective enclosure may be one or more separate enclosures surrounding a single facility or multiple facilities.

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

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

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

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

Sec. 193.2907 Protective enclosure construction.

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

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

Sec. 193.2909 Security communications. A means must be provided for:

(1) Prompt communications between personnel having supervisory security duties and law enforcement officials; and

(2) Direct communications between all on-duty personnel having security duties and all control rooms and control stations.

Sec. 193.2911 Security lighting. Where security warning systems are not provided for security monitoring under Sec. 193.2913, the area around the facilities listed under Sec. 193.2905(a) and each protective enclosure must be illuminated with a minimum in service lighting intensity of not less than 2.2 lux (0.2 ft candles) between sunset and sunrise.

Sec. 193.2913 Security monitoring. Each protective enclosure and the area around each facility listed in Sec. 193.2905(a) must be monitored for the presence of unauthorized persons. Monitoring must be by visual observation in accordance with the schedule in the security procedures under Sec. 193.2903(a) or by security warning systems that continuously transmit data to an attended location. At an LNG plant with less than 40,000 m^3 (250,000 bbl) of storage capacity, only the protective enclosure must be monitored.

Sec. 193.2915 Alternative power sources. An alternative source of power that meets the requirements of Sec. 193.2445 must be provided for security lighting and security monitoring and warning systems required under Secs. 193.2911 and 193.2913.

Sec. 193.2917 Warning signs.

(1) Warning signs must be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 30 m (100 ft) from any way that could reasonably be used to approach the enclosure.

(2) Signs must be marked with at least the following on a background of sharply contrasting color:

The words "NO TRESPASSING," or words of comparable meaning.

Annex D Training

This annex is not a part of the requirements of this NFPA document but is included for informational purposes only.

D.1 General.

This annex is reprinted from Title 49 of the Code of Federal Regulations, Part 193, Subpart H. The references herein are found in 49 CFR 193. It is applicable to LNG plants in the United States under the jurisdiction of the Department of Transportation.

Sec. 193.2701 Scope. This subpart prescribes requirements for personnel qualifications and training.

Sec. 193.2703 Design and fabrication. For the design and fabrication of components, each operator shall use —

(1) With respect to design, persons who have demonstrated competence by training or experience in the design of comparable components.

(2) With respect to fabrication, persons who have demonstrated competence by training or experience in the fabrication of comparable components.

Sec. 193.2705 Construction, installation, inspection, and testing.

(1) Supervisors and other personnel utilized for construction, installation, inspection, or testing must have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related

experience and accomplishments.

(2) Each operator must periodically determine whether inspectors performing duties under Sec. 193.2307 are satisfactorily performing their assigned function.

Sec. 193.2707 Operations and maintenance.

(1) Each operator shall utilize for operation or maintenance of components only those personnel who have demonstrated their capability to perform their assigned functions by —

- (a) Successful completion of the training required by Secs. 193.2713 and 193.2717; and
- (b) Experience related to the assigned operation or maintenance function; and
- (c) Acceptable performance on a proficiency test relevant to the assigned function.

(2) A person who does not meet the requirements of paragraph (a) of this section may operate or maintain a component when accompanied and directed by an individual who meets the requirements.

(3) Corrosion control procedures under Sec. 193.2605(b), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in corrosion control technology.

Sec. 193.2709 Security. Personnel having security duties must be qualified to perform their assigned duties by successful completion of the training required under Sec. 193.2715.

Sec. 193.2711 Personnel health. Each operator shall follow a written plan to verify that personnel assigned operating, maintenance, security, or fire protection duties at the LNG plant do not have any physical condition that would impair performance of their assigned duties. The plan must be designed to detect both readily observable disorders, such as physical handicaps or injury, and conditions requiring professional examination for discovery.

Sec. 193.2713 Training: operations and maintenance.

(1) Each operator shall provide and implement a written plan of initial training to instruct —

- (a) All permanent maintenance, operating, and supervisory personnel —
  - i. About the characteristics and hazards of LNG and other flammable fluids used or handled at the facility, including, with regard to LNG, low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray;
  - ii. About the potential hazards involved in operating and maintenance activities; and
  - iii. To carry out aspects of the operating and maintenance procedures under Secs. 193.2503 and 193.2605 that relate to their assigned functions; and

(b) All personnel —

i. To carry out the emergency procedures under Sec. 193.2509 that relate to their assigned functions; and

ii. To give first-aid; and

(c) All operating and appropriate supervisory personnel —

i. To understand detailed instructions on the facility operations, including controls, functions, and operating procedures; and

ii. To understand the LNG transfer procedures provided under Sec. 193.2513.

(2) A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel current on the knowledge and skills they gained in the program of initial instruction.

Sec. 193.2715 Training: security.

(1) Personnel responsible for security at an LNG plant must be trained in accordance with a written plan of initial instruction to:

(a) Recognize breaches of security;

(b) Carry out the security procedures under Sec. 193.2903 that relate to their assigned duties;

(c) Be familiar with basic plant operations and emergency procedures, as necessary to effectively perform their assigned duties; and

(d) Recognize conditions where security assistance is needed.

(2) A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel having security duties current on the knowledge and skills they gained in the program of initial instruction.

Sec. 193.2717 Training: fire protection.

(1) All personnel involved in maintenance and operations of an LNG plant, including their immediate supervisors, must be trained in accordance with a written plan of initial instruction, including plant fire drills, to:

(a) Know and follow the fire prevention procedures under Sec. 193.2805(b);

(b) Know the potential causes and areas of fire determined under Sec. 193.2805(a);

(c) Know the types, sizes, and predictable consequences of fire determined under Sec. 193.2817(a); and

(d) Know and be able to perform their assigned fire control duties according to the procedures established under Sec. 193.2509 and by proper use of equipment provided under Sec. 193.2817.

(2) A written plan of continuing instruction, including plant fire drills, must be conducted

at intervals of not more than two years to keep personnel current on the knowledge and skills they gained in the instruction under paragraph (a) of the section.

Sec. 193.2719 Training: records.

(1) Each operator shall maintain a system of records which —

(a) Provide evidence that the training programs required by this subpart have been implemented; and

(b) Provide evidence that personnel have undergone and satisfactorily completed the required training programs.

(c) Records must be maintained for one year after personnel are no longer assigned duties at the LNG plant.

Annex E Informational References

E.1 Referenced Publications.

The documents or portions thereof listed in this annex are referenced within the informational sections of this standard and are not part of the requirements of this document unless also listed in Chapter 2 for other reasons.

E.1.1 NFPA Publications. National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02169-7471.

NFPA 10, *Standard for Portable Fire Extinguishers*, 2002 edition.

NFPA 11, *Standard for Low-, Medium-, and High-Expansion Foam*, 2005 edition.

NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*, 2005 edition.

NFPA 12A, *Standard on Halon 1301 Fire Extinguishing Systems*, 2004 edition.

NFPA 13, *Standard for the Installation of Sprinkler Systems*, 2002 edition.

NFPA 14, *Standard for the Installation of Standpipe and Hose Systems*, 2003 edition.

NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*, 2001 edition.

NFPA 16, *Standard for the Installation of Foam-Water Sprinkler and Foam-Water Spray Systems*, 2003 edition.

NFPA 17, *Standard for Dry Chemical Extinguishing Systems*, 2002 edition.

NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*, 2003 edition.

NFPA 22, *Standard for Water Tanks for Private Fire Protection*, 2003 edition.

NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*, 2002 edition.

NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire*

Protection Systems, 2002 edition.

NFPA 30, *Flammable and Combustible Liquids Code*, 2003 edition.

NFPA 52, *Vehicular Fuel Systems Code*, 2006 edition.

NFPA 68, *Guide for Venting of Deflagrations*, 2002 edition.

NFPA 69, *Standard on Explosion Prevention Systems*, 2002 edition.

NFPA 70, *National Electrical Code*®, 2005 edition.

NFPA 72®, *National Fire Alarm Code*®, 2002 edition.

NFPA 77, *Recommended Practice on Static Electricity*, 2000 edition.

NFPA 255, *Standard Method of Test of Surface Burning Characteristics of Building Materials*, 2006 edition.

NFPA 600, *Standard on Industrial Fire Brigades*, 2005 edition.

NFPA 750, *Standard on Water Mist Fire Protection Systems*, 2003 edition.

NFPA 780, *Standard for the Installation of Lightning Protection Systems*, 2004 edition.

NFPA 850, *Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations*, 2005 edition.

NFPA 1961, *Standard on Fire Hose*, 2002 edition.

NFPA 1962, *Standard for the Inspection, Care, and Use of Fire Hose, Couplings, and Nozzles and the Service Testing of Fire Hose*, 2003 edition.

NFPA 1963, *Standard for Fire Hose Connections*, 2003 edition.

NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*, 2004 edition.

E.1.2 Other Publications.

E.1.2.1 AGA Publication. American Gas Association, 400 N. Capitol Street, N.W., Washington, DC 20001.

Purging, Principles and Practice, 1975.

E.1.2.2 API Publications. American Petroleum Institute, 1220 L Street, N.W., Washington, DC 20005-4070.

API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* 1990.

API RP 651, *Cathode Protection of Aboveground Petroleum Storage Tanks,* 1997.

API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents,* 1991.

E.1.2.3 ASCE Publications. American Society of Civil Engineers, 1801 Alexander Bell Drive, Reston, VA 20191.

ASCE 7, *Minimum Design Loads for Buildings and Other Structures,* 1993.

ASCE 56, *Subsurface Investigation for Design and Construction of Foundation for Buildings,* 1976.

E.1.2.4 ASME Publications. American Society of Mechanical Engineers, Three Park Avenue, New York, NY 10016-5990.

ASME *Boiler and Pressure Vessel Code,* 1992.

ASME A 13.1, *Scheme for the Identification of Piping Systems,* 1981.

ASME B31.8, *Gas Transmission and Distribution Piping Systems,* 1992.

E.1.2.5 ASTM Publication. American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959.

ASTM E 136, *Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C,* 2004.

E.1.2.6 Canadian Geotechnical Society Publication. Available from B1-Tech Pub. Ltd., 173-11860 Hammersmith Way, Richmond, BC V7A 5G1, Canada.

Canadian Foundation Engineering Manual, 1993.

E.1.2.7 ICC Publication. International Code Council, 5203 Leesburg Pike, Suite 600, Falls Church, VA 22041.

International Building Code (IBC), 2003.

E.1.2.8 NACE Publication. NACE International, 1440 South Creek Drive, Houston, TX 77084-4906.

NACE RP 0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems,* 2002.

E.1.2.9 U.S. Government Publications. U.S. Government Printing Office, Washington, DC 20402.

Title 29, Code of Federal Regulations, Part 1910.146, "Permit-Required Confined Spaces," January 14, 1993, effective April 15, 1993.

Title 49, Code of Federal Regulations, Part 191, "Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports."

Title 49, Code of Federal Regulations, Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Standards."

Title 49, Code of Federal Regulations, Part 193, "Liquefied Natural Gas Facilities: Federal Safety Standards."

E.1.2.10 Other Publications. Canadian Federal Employment and Labor Statutes, Part II.

E.2 Informational References. (Reserved)

E.3 References for Extracts in Informational Sections. (Reserved)

Formal Interpretations

Formal Interpretation

NFPA 59A

Liquefied Natural Gas (LNG)

2006 Edition

Reference: 8.4
F.I. 79-1

Question: An open panel LNG vaporizer has the following characteristics:

1. LNG is supplied to the vaporizer by LNG supply pumps and a means is provided to shut off the flow of LNG to the panels.

2. Seawater is supplied by pumps, and the vaporizer is provided with a means to shut off the flow of sea water to the panels as required by NFPA 59A for heated vaporizers.

3. The maximum allowable working pressure of the LNG system exceeds the maximum LNG pump discharge pressure.

4. The equipment is selected such that the LNG flow to the vaporizer at the maximum allowable working pressure is zero.

Is it the intent of NFPA 59A, 8.4 that a safety relief valve(s) for such an LNG vaporizer be sized in accordance with 5.4.1.1 and 5300, respectively.

Answer: Yes. The vaporizer described is considered to be a remote heated vaporizer.

Issue Edition: 1979
Reference: 5-4.1
Date: August 1982

Formal Interpretation

NFPA 59A

Liquefied Natural Gas (LNG)

2006 Edition

Reference: **9.2.4**
F.I.

Question: Can a fuel control valve having a body of cast iron be classified for service in the fuel burning system on an LNG vaporizer in the case where the fuel control valve is not the safety shutoff valve nor is it used for safety shutdown?

Answer: Paragraph 9.2.4 of NFPA 59A specifies provisions for valves. Under the referenced standard, ANSI-B31.3, Section 300.1.4(a), valves within the following design condition ranges are not subject to the specified rules and the responsibility for safety is the designer's and the owner's.

Press. (psig)	Temp. (°F)
0-15	−20°F to +360°F

Further, because of fire hazard, it is the opinion of the Chapter 9 Subcommittee that the safety shutoff valve upstream of the fuel control valve shall be steel or cast steel.

Issue Edition: 1972
Reference: 613
Date: January 1974

Formal Interpretation

NFPA 59A

Liquefied Natural Gas (LNG)

2006 Edition

Reference: Chapter 12
F.I. No.: 59A-01-1

Question: Was it the intent of NFPA 59A that the editions of referenced NFPA standards for fire protection requirements in Chapter 12 be applied to LNG plants placed into operation prior to the effective date of the 2006 edition of NFPA 59A?

Answer: No

Issue Edition: 2001
Reference: Chapter 9
Issue Date: January 15, 2004
Effective Date: February 4, 2004

Formal Interpretation

NFPA 59A

Liquefied Natural Gas (LNG)

2006 Edition

Reference: **Chapter 13**
F.I. No.: **59A-96-1**

Question: Is it the intent of the LNG Committee to require that Chapter 13 of NFPA 59A be applicable to all facilities using LNG containers designed and constructed in accordance with the ASME Boiler and Pressure Vessel Code for use in commercial and industrial applications as well as vehicle refueling facilities?

Answer: Yes.

Issue Edition: **1996**
Reference: **Chapter 10**
Issue Date: **December 23, 1997**
Effective Date: **January 12, 1998**

Tentative Interim Amendment

Tentative Interim Amendment

NFPA 59A

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

2006 Edition

Reference: 2.3.2
TIA 06-1 (NFPA 59A)
(SC 06-1-4/Log No. 831)

Pursuant to Section 5 of the NFPA Regulations Governing Committee Projects, the National Fire Protection Association has issued the following Tentative Interim Amendment to NFPA 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*, 2006 edition. The TIA was processed by the Liquefied Natural Gas Committee, and was issued by the Standards Council on January 26, 2006, with an effective date of February 14, 2006.

A Tentative Interim Amendment is tentative because it has not been processed through the entire standards-making procedures. It is interim because it is effective only between editions of the standard. A TIA automatically becomes a proposal of the proponent for the next edition of the standard; as such, it then is subject to all of the procedures of the standards-making process.

Revise the dates of the following API publications as follows:

2.3.2 API Publications. American Petroleum Institute, 1220 L Street, N.W.,Washington, DC 20005-4070.

API 6D, *Specification for Pipeline Valves,* ~~1994~~ 2005.

API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks,* ~~1990~~ 2004.

API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations,* ~~1989~~ 2001.

Tentative Interim Amendment

NFPA 59A

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

2006 Edition

Reference: 5.2.2.1 (2) and (4)
TIA 06-2 (NFPA 59A)
(SC 06-7-15/Log No. 840)

Pursuant to Section 5 of the NFPA Regulations Governing Committee Projects, the National Fire Protection Association has issued the following Tentative Interim Amendment to NFPA 59A, *Standard for the Protection, Storage and Handling of Liquefied Natural Gas (LNG)*, 2006 edition. The TIA was processed by the Liquefied Natural Gas Committee, and was issued by the Standards Council on July 28, 2006, with an effective date of August 19, 2006.

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1. Replace existing paragraph 5.2.2.1 (2) with the following:

(2) For impounding areas serving more than one container without provision made in accordance with 5.2.2.1 (4) V equals 100 percent of the total volume of liquid in all tanks served, assuming all tanks are full.

2. Add new paragraph 5.2.2.1 (4)

(4) For impounding areas serving more than one tank with provision made to prevent low temperature or fire exposure resulting from leakage from any one tank served from causing subsequent leakage from any other tank served, V equals 110 percent of the total volume of liquid in the largest tank served, assuming the tank is full.

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NFPA 59A

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

2006 Edition

Reference: 5.2.4.1, 5.2.4.2 and 5.2.4.3
TIA 06-3 (NFPA 59A)
(SC 06-11-6/Log No. 859)

Pursuant to Section 5 of the NFPA Regulations Governing Committee Projects, the National Fire Protection Association has issued the following Tentative Interim Amendment to NFPA 59A, *Standard for the Production,, Storage, and Handling of Liquefied Natural Gas (LNG),* 2006 edition. The TIA was processed by the Liquefied Natural Gas Committee, and was issued by the Standards Council on November 3, 2006, with an effective date of November 23, 2006.

A Tentative Interim Amendment is tentative because it has not been processed through the entire standards-making procedures. It is interim because it is effective only between editions of the standard. A TIA automatically becomes a proposal of the proponent for the next edition of the standard; as such, it then is subject to all of the procedures of the standards-making process.

1. Revise 5.2.4.1 to read:
5.2.4.1 The minimum separation distance between LNG containers of 70,000 gal (265m^3) water capacity or less or tanks containing flammable refrigerants and exposures shall be in accordance with Table 5.2.4.1 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.

2. Revise 5.2.4.2 to read:
5.2.4.2 LNG storage containers of greater than 70,000 gal (265m^3) water capacity shall be separated from adjoining LNG storage containers such that a fire in one container or impoundment will not cause the failure of adjacent containers or impoundments unless the Thermal Radiation Flux Limit Distances as calculated by 5.2.3 are also met when all adjacent container impoundments are assumed involved in the fire . 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:

(A) The analyses shall be performed for:

(1) A fire involving the complete loss of containment of a container to an impoundment area that complies with the requirements of 5.2.2.1

(2) A fire over the whole surface of the liquid contained in the tank assuming the roof is completely lost

(B) The analyses shall account for:

(1) 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,

(2) The atmospheric conditions producing the maximum separation distances shall be used except for conditions that occur less than 5% of the time based on recorded data for the area and using the LNG fire model in accordance with 5.2.3.3 (1) or an alternate model in accordance with 5.2.3.3(2),

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

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

3. Add a new 5.2.4.3 to read:

5.2.4.3 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 5.2.4.1.

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