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NFPA 59A Production, Storage, and Handling of Liquefied Natural Gas (LNG)

1990 Edition

NFPA

National Fire Protection Association 1 Batterymarch Park, Quincy, MA 02269-9101

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Policy Adopted by NFPA Board of Directors on December 3, 1982

The Board of Directors reaffirms that the National Fire Protection Association recognizes that the toxicity of the products of combustion is an important factor in the loss of life from fire. NFPA has dealt with that subject in its technical committee documents for many years.

There is a concern that the growing use of synthetic materials may produce more or additional toxic products of combustion in a fire environment. The Board has, therefore, asked all NFPA technical committees to review the documents for which they are responsible to be sure that the documents respond to this current concern. To assist the committees in meeting this request, the Board has appointed an advisory committee to provide specific guidance to the technical committees on questions relating to assessing the hazards of the products of combustion.

Statement on NFPA Procedures

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NFPA 59A

Standard for the

Production, Storage, and Handling of

Liquefied Natural Gas (LNG)

1990 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 the National Fire Protection Association, Inc. at its Fall Meeting held November 13-15, 1989 in Seattle, WA. It was issued by the Standards Council on January 12, 1990, with an effective date of February 5, 1990, and supersedes all previous editions.

The 1990 edition of this document has been approved by the American National Standards Institute.

Changes other than editorial are indicated by a vertical rule in the margin of the pages on which they appear. These lines are included as an aid to the user in identifying changes from the previous edition.

Origin and Development of NFPA 59A

Work on this standard was initiated by a Committee of the American Gas Association, Inc., about 1960. In the Fall 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 which was tentatively adopted at the 1966 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 Annual Meeting under the sponsorship of the Committee on Fuel Gases.

By early 1969, it was apparent that the usage of LNG was being broadened considerably beyond the utility gas plant applications covered by the 1967 edition. The American Petroleum Institute suggested that its standard 2510A be used to help develop a standard having a broader scope. The Committee on Liquefied Natural Gas was established to accomplish this. The 1971 edition was the first edition developed under the broadened scope. Subsequently, editions were adopted in 1972, 1975, 1979, and 1985.

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This list represents the membership at the time the Committee was balloted on the text of this edition. Since that time, changes in the membership may have occurred.

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.

Contents

NFPA 59A

Standard for the

Production, Storage and Handling of

Liquefied Natural Gas (LNG)

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NOTICE: Information on publications can be found in Chapter 10 and Appendix A.

Chapter 1 Introduction

1-1 Preface.

1-1.1 This standard outlines basic methods of equipment fabrication and installation as well as operating practices for protection of persons and property and provides guidance to all persons concerned with the construction and operation of equipment for the production, storage, and handling of liquefied natural gas (LNG).

1-1.2 It is recognized that advancements in engineering and improvements in equipment may result in equipment fabrication methods and operating practices that differ from those specifically called for in this standard. Yet such deviations or improvements may provide desirable safety and compatible operation meeting the intent of this standard. Such deviations may be accepted when the authority having jurisdiction has made a special investigation of all factors and, based on sound experience and engineering judgment, concludes that the proposed deviations meet the intent of this standard.

1-1.3 Where existing plants, equipment, buildings, structures, and installations meet the applicable design, fabrication, or construction layout provisions of the edition of this standard in effect at the time of installation, they may be continued in use provided they do not constitute a distinct hazard to life or adjoining property.

1-1.4 In the interest of safety, it is important that persons engaged in handling LNG understand the properties of this product and that they be thoroughly trained in safe practices for its handling.

1-1.5 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).

1-1.6 Upon release from containment to the atmosphere, LNG will vaporize and release gas that, at ambient temperature, will have about 600 times the volume of the liquid vaporized. Generally at temperatures below approximately -170°F (-112°C) this gas is heavier than ambient air at 60°F (15.6°C). However, as its temperature rises, it then becomes lighter than air.

NOTE: The -170°F (-112°C) temperature value is for methane. If other constituents are present see definition of Liquefied Natural Gas, the temperature will be different.

1-1.7 Metric units in this standard are based upon the ASTM *Metric Practice Guide*. Where clearance distances are to be determined, the conversion from English to metric units shall be calculated to the nearest one-half meter. Alternate usage of English and metric units on a single project shall not be used to lessen clearance distances.

1-2 Scope.

1-2.1 This standard applies to the design, location, construction, and operation of facilities at any location for the liquefaction of natural gas and the storage, vaporization, transfer, handling, and truck transport of liquefied natural gas (LNG).

1-2.2 This standard covers all containers except frozen ground containers as used for the storage of liquefied natural gas containers. Metal containers are classified in two groups:

(a) For operation at a pressure of 15 psig (103 kPa) and less

(b) For operation at a pressure more than 15 psig (103 kPa).

Containers with insulation systems applying vacuum are included in these classifications.

1-3 Definitions.

Approved. Acceptable to the "authority having jurisdiction."

NOTE: 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 or 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 concerned with product evaluations which is in a position to determine compliance with appropriate standards for the current production of listed items.

Authority Having Jurisdiction. The "authority having jurisdiction" is the organization, office or individual responsible for "approving" equipment, an installation or a procedure.

NOTE: The phrase "authority having jurisdiction" 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, 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 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."

Barrel. A unit of volume. One barrel equals 42 US gal or 5.615 cu ft (0.159 m^3).

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

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

Container. A vessel for storing liquefied natural gas. Such a vessel may be above, partially below, or totally below ground and may consist of an inner and outer tank.

Container, Frozen Ground. A container in which the maximum liquid level is below the normal surrounding grade and is constructed essentially of natural materials, such as earth and rock, and dependent upon the freezing of water-saturated earth materials with appropriate methods for its tightness or impervious nature. (This type of storage is still under development. It is, therefore, not included in Chapter 4 at this time.)

Container, Prestressed Concrete. A concrete container is considered to be prestressed when the stresses created by the different loadings or loading combinations do not exceed allowable stresses provided for in this standard. Either circumferential prestressing or both circumferential and vertical prestressing may be required to meet these provisions.

Deriming. Deriming, synonymous with defrosting or deicing, refers to the removal, by heating and evaporation, sublimation, or solution, of accumulated constituents that form solids, such as water, carbon dioxide, etc., from the low-temperature process equipment.

Design Pressure. The pressure used in the design of equipment, a container, or a vessel for the purpose of determining the minimum permissible thickness or physical characteristics of its different parts. When applicable, static head shall be included in the design pressure to determine the thickness of any specific part.

Dike. A structure used to establish an impounding area.

Failsafe. Design features that provide for the maintenance of safe operating conditions in the event of a malfunction of control devices or an interruption of an energy source.

Fired Equipment. Any equipment in which the combustion of fuels takes place. Included, among others, are fired boilers, fired heaters, internal combustion engines, certain integral heated vaporizers, the primary heat source for remote heated vaporizers, gas-fired oil foggers, fired regeneration heaters, and flared vent stacks.

Fixed-Length Dip Tube. A pipe that has a fixed open end inside a container at a designated elevation that is intended to show a liquid level.

Flame Spread Rating. The flame spread rating of materials as determined in accordance with NFPA 255, *Method of Test of Surface Burning Characteristics of Building Materials.*

G. The normal or standard constant of gravity. At sea level, "G" equals approximately 32.2 ft/sec^2 (9.81 m/sec^2).

Ignition Source. Any item or substance capable of an energy release of type and magnitude sufficient to ignite any flammable mixture of gases or vapors that could occur at the site.

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

Liquefied Natural Gas. A fluid in the liquid state composed predominantly of methane and which may contain minor quantities of ethane, propane, nitrogen, or other components normally found in natural gas.

LNG. An abbreviation for "liquefied natural gas."

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

Primary Component. Primary components, as referred to in Chapter 4, include those which may be stressed to a significant level, those whose failure would permit leakage of the LNG being stored, those exposed to a temperature between -60°F (-51°C) and -270°F (-168°C), and those subject to thermal shock. Primary components include, but are not limited to, the following parts of a single-wall tank or of the inner tank in a double-wall tank: shell plates, bottom plates, roof plates, knuckle plates, compression rings, shell stiffeners, manways, and nozzles, including reinforcement, shell anchors, pipe, tubing, forging, and bolting.

Process Plant. All systems required to condition, liquefy, or vaporize natural gas in all areas of application as identified under the scope of this standard.

PSIA. Pounds per square inch absolute.

PSIG. Pounds per square inch gage.

Secondary Components. Secondary components, as referred to in Chapter 4, include those which will not be stressed to a significant level, those whose failure will not result in leakage of the LNG being stored, or those exposed to the boiloff gas and having a design metal temperature of -60°F (-51°C) or higher.

Shall. Indicates a mandatory requirement.

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

Transfer Area. That portion of an LNG plant containing piping systems where LNG, flammable liquids, or flammable refrigerants are introduced into or removed from the facility, such as truck loading or ship unloading areas, or where piping connections are routinely connected or disconnected. Transfer areas do not include product sampling devices or permanent plant piping.

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 usual welding or joining techniques.

Chapter 2 General Plant Considerations

2-1 Plant Site — General.

2-1.1 Some factors to be considered in selection of plant site locations are:

(a) 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 to each other

(b) Accessibility to plant; at least one all-weather vehicular road shall be provided

(c) The degree to which the plant can, within limits of practicality, be protected aginst forces of nature

(d) Other factors applicable to the specific site that could have a bearing on the safety of plant personnel and the surrounding public. The review of such factors shall include an evaluation of potential incidents and appropriate safety measures incorporated in the design or operation of the facility.

2-1.2 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.

2-2 Major Site Provisions for Spill and Leak Control.

2-2.1 General.

2-2.1.1 One of the following provisions shall be made to minimize the possibility of accidental discharge of LNG at containers from endangering adjoining property or important process equipment and structures, or reaching waterways (*see 2-2.1.3*):

(a) An impounding area surrounding the container(s) formed by a natural barrier, dike, impounding wall (or combination thereof) complying with 2-2.2 and 2-2.3, or

(b) An impounding area formed by a natural barrier, dike, excavation, impounding wall (or combination thereof) complying with 2-2.2 and 2-2.3 plus a natural or man-made drainage system surrounding the container(s) that complies with 2-2.2 and 2-2.3, or

(c) Where the container is constructed below or partially below the surrounding grade, an impounding area formed by the excavation complying with 2-2.2 and 2-2.3.

2-2.1.2 The following areas shall be graded, drained, or provided with impoundment in a manner that will minimize the possibility of accidental spills and leaks from endangering important structures, equipment, or adjoining property or from reaching waterways (*see 2-2.1.3*):

(a) Process areas

(b) Vaporization areas

(c) Transfer areas for LNG, flammable refrigerants, and flammable liquids

(d) Areas immediately surrounding flammable refrigerant and flammable liquid storage tanks.

If impounding areas are also required in order to comply with 2-1.2, such areas shall be in accordance with 2-2.2 and 2-2.3.

2-2.1.3 In particular installations, the provisions of 2-1.2, 2-2.1.1, and 2-2.1.2 applicable to adjoining property or waterways may be waived or altered at the discretion of the authority having jurisdiction when the change does not constitute a distinct hazard to life or property or conflict with applicable federal, state, and local regulations.

2-2.1.4 Flammable liquid and flammable refrigerant storage tanks shall not be located within an LNG container impounding area.

2-2.2 Impounding Area and Drainage System Design and Capacity.

2-2.2.1 Impounding areas serving LNG containers shall have a minimum volumetric holding capacity, V, 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 2-2.2.1(a) through (c).

(a) For impounding areas serving a single container,

V = Total volume of liquid in the container assuming the container is full.

(b) For impounding areas serving more than one container with provision made to prevent low temperature or fire exposure resulting from leakage from any one container served from causing subsequent leakage from any other container served,

V = Total volume of liquid in the largest container served assuming the container is full.

(c) For impounding areas serving more than one container without provision made in accordance with 2-2.2.1(b),

V = Total volume of liquid in all containers served assuming all containers are full.

2-2.2.2 Impounding areas, if provided to 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 could be discharged into the area during a 10-minute period from any single accidental leakage source or a lesser time period based upon demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction.

2-2.2.3 Enclosed drainage channels for LNG are prohibited.

Exception: Container downcomers used to rapidly conduct spilled LNG away from critical areas may be enclosed provided that an adequate drainage rate is achieved.

2-2.2.4 Dikes, impounding walls, and drainage systems for LNG and flammable refrigerant containment shall be of compacted earth, concrete, metal, and/or other suitable materials. They may be independent of the container or they may be mounded, integral to, or constructed against the container. They, 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 earthquake, wind, and rain. Where the outer shell of a double wall tank complies with these requirements, it may be considered as the impounding area for purposes of determining the siting area distances in 2-2.3. When the containment integrity of such an outer shell can be affected by an inner tank failure mode, an additional impounding area that otherwise satisifes the requirements of 2-2.1.1 shall be provided.

2-2.2.5 Dikes, impounding walls, and drainage channels for flammable liquid containment shall conform to NFPA 30, *Flammable and Combustible Liquids Code*.

2-2.2.6 To assure that any accidentally discharged liquid stays confined within an area enclosed by a dike or impounding wall and yet to provide a reasonably wide margin for area configuration design, the dike or impounding wall height and distance from containers shall be determined in accordance with Figure 2-1.

2-2.2.7 Provision shall be made to clear rain or other water from the impounding area. Automatically controlled sump pumps are permitted if equipped with an automatic cutoff device that shall prevent their operation when exposed to LNG temperatures. Piping, valves, and fittings whose failure could permit liquid to escape from the impounding area shall be suitable for continuous exposure to LNG temperatures. If gravity drainage is employed for water removal, provision shall be made to prevent the escape of LNG by way of the drainage system.

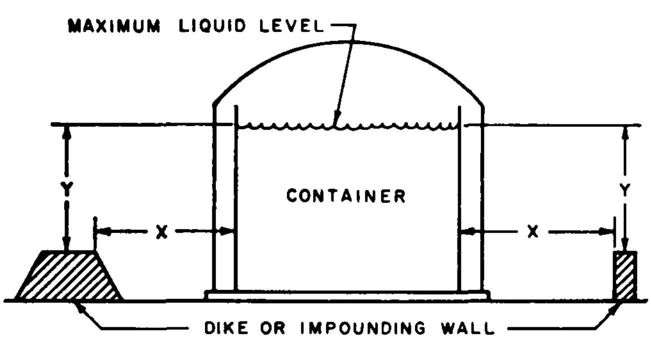

Figure 2-1 Dike or impounding wall proximity to containers.

Notes to Figure 2-1:

Dimension "X" must equal or exceed the sum of dimension "Y" plus the equivalent head in LNG of the pressure in the vapor space above the liquid.

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

Dimension "X" is the distance from the inner wall of the container to the closest face of the dike or impounding wall.

Dimension "Y" is the distance from the maximum liquid level in the container to the top of the dike or impounding wall.

2-2.2.8 Insulation systems used for impounding surfaces shall be, in the installed condition, noncombustible and suitable for the intended service considering the anticipated thermal and mechanical stresses and loadings. If flotation is a problem, mitigating measures shall be provided. Such insulation systems shall be inspected as appropriate for their intended service.

2-2.3 Impounding Area Siting.

2-2.3.1 Thermal radiation protection distances shall be determined in accordance with 2-2.3.1(a) through (9d).

(a) Provision shall be made to prevent a radiation flux that could result from ignition of a design spill (defined in 2-2.3.3) from exceeding 1600 Btu/hr/ft^2 (5000 W/m^2) at a property line that can be built upon when atmospheric conditions are zero wind speed, 70°F (21°C) temperature, and 50 percent relative humidity. This provision may be complied with by a separation distance determined by Formula 1(a).

Formula 1(a)

$$d_1 = 3\sqrt{A_1}$$

where

d_1 = distance, in ft (m), from the nearest edge of the applicable design spill to a property line that can be built upon.

A_1 = surface area, in ft^2 (m^2) of LNG, resulting from the applicable design spill.

(b) Provision shall be made to prevent a radiation flux from a fire over an LNG impounding area from exceeding 1600 Btu/hr/ft^2 (5000 W/m^2) at the nearest point of a place 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 when atmospheric conditions are zero wind speed, 70°F (21°C) temperature, and 50 percent relative humidity. This provision may be complied with by a separation distance determined by Formula 1(b).

Formula 1(b)

$$d_2 = 3\sqrt{A_2}$$

where

d_2 = distance, in ft (m), from the edge of impounded LNG to the nearest point of the place of assembly.

A_2 = surface area, in ft^2 (m^2), of impounding area is filled with a volume, V, determined in accordance with 2-2.2.1.

(c) Provision shall be made to prevent a radiation flux from a fire over an LNG impounding area from exceeding 3000 Btu/hr/ft^2 (9000 W/m^2) at the nearest point of a building or structure outside the owner's property line in existence at the time of plant siting and used for purposes classified by NFPA *101®*, *Life Safety Code®*, as Assembly, Educational, Health Care, Detention and Correction, or Residential when atmospheric conditions are zero wind speed, 70°F (21°C) temperature, and 50 percent relative humidity. This provision may be complied with by a separation distance determined by Formula 1(c).

Formula 1(c)

$$d_3 = 2\sqrt{A_3}$$

where

d_3 = distance, in ft (m), from the edge of impounded LNG to the nearest point of the building or structure.

A_3 = surface area, in ft^2 (m^2), of impounded LNG when the impounding area is filled with a volume, V, determined in accordance with 2-2.2.1.

(d) Provision shall be made to prevent a radiation flux from a fire over an LNG impounding area from exceeding 10,000 Btu/hr/ft^2 (30,000 W/m^2) at a property line that can be built upon when ambient atmospheric conditions are zero wind speed, 70°F (21°C) temperature, and 50 percent relative humidity. This provision may be complied with by a separation distance determined by Formula 1(d).

Formula 1(d)

$$d_4 = 0.8\sqrt{A_4}$$

where

d_4 = distance, in ft (m), from the edge of impounded LNG to a property line that may be built upon.

A_4 = surface area, in ft^2 (m^2), of impounded LNG when the impounding area is filled with a volume, V, determined in accordance with 2-2.2.1.

(e) As an alternative for irregularly shaped areas (such as trenches), the above distances may be computed using a suitable model acceptable to the authority having jurisdiction.

2-2.3.2 Provision shall be made to minimize the possibility of a flammable mixture of vapors from a "design spill," as defined in 2-2.3.3(a), (b), (c) or (d), as appropriate, from reaching a property line that may be built upon at an elevation above grade that would result in a distinct hazard. Flammable mixture dispersion distances shall be determined in accordance with 2-2.3.2(a) through (e).

(a) Distances shall be computed in accordance with a suitable model.

(b) The method used may be based on applicable parts of the mathematical model in "Evaluation of LNG Vapor Control Methods," American Gas Association, or other suitable method.

(c) The method used shall be based upon the combination wind speed and atmospheric stability that may occur simultaneously and result in the longest predictable downwind dispersion distance which is exceeded less than 10 percent of the time, or, as an alternate, Pasquill-Gifford stability Category F with a 4.5 mph (2 m/sec) wind speed may be assumed and used.

(d) The method used shall be based upon 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).

(e) The presence of methods for detaining the vapor formed as a result of spills or otherwise mitigating the hazard (e.g., impounding surface insulation, water curtains, or other suitable methods) may be considered provided there exists demonstrable surveillance and functional provisions acceptable to the authority having jurisdiction.

2-2.3.3 The "design spill" shall be determined in accordance with 2-2.3.3(a) through (d).

(a) For impounding areas serving LNG containers that have penetrations below the liquid level without internal valves, the "design spill" is defined as flow through an assumed opening at and equal in area to that penetration below the liquid level that would result in the largest flow from an initially full container. The flow, as determined by Formula 2, is assumed to continue until the differential head acting on the opening is zero. For impounding areas serving more than one container, the "design spill" shall be applied to the container that results in the largest flow.

(b) For impounding areas serving LNG containers with "over-the-top" fill and withdrawal connections and that have no tank penetrations below the liquid level, the "design spill" is defined as 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 full rated capacity. The time duration of the "design spill" shall be 10 minutes provided there exists demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction; otherwise, the time duration shall be until the initially full container has emptied.

(c) For impounding areas serving LNG containers that have all penetrations below the liquid level fitted with internal shutoff valves in accordance with 6-3.3.3, the "design spill" is defined as 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. The flow shall be the maximum computed from Formula 2 with the flow "q" lasting for a period of 1 hour provided there exists demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction; otherwise, the time duration shall be until the initially full container has emptied.

Formula 2

$$q = \frac{4}{3} d^2 \sqrt{h}$$

where

q = flow rate, in cubic feet per minute, of liquid

d = diameter, in inches, of tank penetration below the liquid level

h = height, in feet, of liquid above penetration in the container when the container is full.

(d) For impounding areas serving only vaporization, process, or LNG transfer areas, the "design spill" is defined as flow during a 10-minute period from any single accidental leakage source, or a lesser time period based upon demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction.

2-2.3.4 LNG container impounding areas shall be located such 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.

2-2.3.5 In no case shall the distance from the nearest edge of impounded liquid to a property line that may be built upon, or the near edge of a navigable waterway as defined by federal regulations, be less than 50 ft (15 m).

2-2.3.6 The provisions of 2-2.3 do not apply to impounding areas serving only transfer areas at water's edge of marine terminals.

2-2.4 Container Spacing.

2-2.4.1 LNG containers and tanks containing flammable refrigerants not covered by Section 3-3 shall be sited in accordance with Table 2-1.

Table 2-1 Container Spacing

	Minimum Clear Distances	
Water Capacity per Container	From Container to Property Line Which May Be Built Upon	Between Any Two Adjacent Containers
Less than 125 gal (473 L)*	None	None
125 to 250 gal (473 to 946 L)	10 ft (3 m)	None
251 to 500 gal (950 to 1892 L)	10 ft (3 m)	3 ft (1 m)
501 to 2,000 gal (1.9 to 7.6 m^3)	25 ft (7.6 m)	3 ft (1 m)
2,001 to 30,000 gal (7.6 + to 113 m^3)	50 ft (15 m)	5 ft (1.5 m)
30,001 to 70,000 gal (113 + to 265 m^3)	75 ft (23 m)	10 ft (3 m)
Above 70,000 gal (265 m^3)	0.7 times the container diameter but not less than 100 ft (30 m).	¼ of sum of diameters of the two adjacent containers but not less than 25 ft (7.6 m).

*If the aggregate water capacity of a multicontainer 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 another installation by at least 25 ft (7.6 m). Do not apply the minimum distances between adjacent containers to such installations.

2-2.5 Vaporizer Spacing. *(See Chapter 5 for vaporizer classification.)*

2-2.5.1 Vaporizers and their primary heat sources, unless the intermediate heat transfer fluid is nonflammable, shall be located at least 50 ft (15 m) from any other source of ignition. In multiple vaporizer installations, an adjacent vaporizer or primary heat source is not considered to be a source of ignition.

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

2-2.5.2 Except as provided in 2-2.5.5, integral heated vaporizers shall be located at least 100 ft (30 m) from a property line that may be built upon (*see 2-2.5.4*) and at least 50 ft (15 m) from:

(a) Any impounded LNG, flammable refrigerant, or flammable liquid (*see 2-2.4*), or the paths of travel of such fluids between any other source of accidental discharge and the impounding area.

(b) 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.

(c) Control buildings, offices, shops, and other occupied or important plant structures.

2-2.5.3 Heaters or heat sources of remote heated vaporizers shall comply with 2-2.5.2, except, if the intermediate heat transfer liquid is nonflammable, the property line clearance and 2-2.5.2(c) do not apply.

2-2.5.4 Except as provided in 2-2.5.5, remote heated, ambient, and process vaporizers shall be located at least 100 ft (30 m) from a property line that can be built upon. Remote heated and ambient vaporizers may be located within an impounding area.

2-2.5.5 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 2-1 considering the vaporizer as a container of the same size as the largest container to which it is connected.

2-2.5.6 In multiple heated vaporizer installations, a clearance of at least 5 ft (1.5 m) shall be maintained between vaporizers.

2-2.6 Process Equipment Spacing.

2-2.6.1 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 may be built upon, from control rooms, offices, shops, and other occupied structures, except that control rooms may be located in a building housing flammable gas compressors if the building construction complies with 2-3.1.1.

2-2.6.2 Fired equipment and other sources of ignition shall be located at least 50 ft (15 m) from any impounding area or container drainage system.

2-2.7 Loading and Unloading Facility Spacing.

2-2.7.1 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. The loading or unloading manifold shall be at least 200 ft (61 m) from such a bridge.

2-2.7.2 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. This does not apply to structures or equipment directly associated with the transfer operation.

2-3 Buildings and Structures.

2-3.1 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.

2-3.1.1 If rooms containing such fluids are located within or attached to buildings in which such fluids are not handled, i.e., control rooms, shops, etc., the common walls shall be limited to no more than two in number, 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.

2-3.2 The buildings or structural enclosures cited in Section 2-3 shall be ventilated to minimize the possibility of hazardous accumulations of flammable gases or vapors in accordance with 2-3.2.1 through 2-3.2.3.

2-3.2.1 Ventilation may be by means of:

(a) A continuously operating mechanical ventilation system, or

(b) A combination gravity ventilation system and normally off mechanical ventilation system that is energized by suitable combustible gas detectors in the event combustible gas is detected, or

(c) A dual rate mechanical ventilation system with the high rate energized by suitable gas detectors in the event flammable gas is detected, or

(d) A gravity ventilation system composed of a combination of wall openings and roof ventilators. If there are basements or depressed floor levels a supplemental mechanical ventilation system shall be provided.

2-3.2.2 The ventilation rate shall be at least 1 cfm of air per square foot (5 L/s per m^2) of floor area.

2-3.2.3 If vapors heavier than air can be present, a suitable part of the ventilation must be from the lowest level exposed to such vapors.

2-3.3 Buildings or structural enclosures not covered by 2-3.1 and 2-3.2 shall be either located, or provision otherwise made, to minimize the possibility of entry of flammable gases or vapors. (*See 9-4.1.*)

2-4 Designer and Fabricator Competence.

2-4.1 Designers and fabricators of LNG facilities shall have competence in the design or fabrication of LNG containers, process equipment, refrigerant storage and handling equipment, loading and unloading facilities, fire protection equipment, and other components of the facility.

2-4.1.1 Adequate supervision shall be provided for the fabrication and all acceptance tests of facility components to the extent necessary to assure that they are structurally sound, suitable for the service, and otherwise in compliance with this standard.

2-4.1.2 Sufficient soil and general investigations shall be made to determine the adequacy of the intended site for the facility. (*See ASCE 56, Sub-Surface Investigation for Design and Construction of Foundation for Buildings, and Appendix C of API 620 for further information.*)

2-5 Soil Protection for Cryogenic Equipment.

2-5.1 LNG containers (*see 4-1.7*), cold boxes, piping and pipe supports, and other cryogenic apparatus shall be properly designed and constructed to prevent damage to these structures and equipment from freezing or frost heaving in the soil, or suitable means shall be provided to prevent damaging forces from developing.

NOTE: Soil movements due to freezing of water are of two general gypes: (1) The freezing of in situ water can cause 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.

2-6 Falling Ice and Snow.

2-6.1 Where appropriate, suitable measures shall be taken to protect personnel and equipment from falling ice or snow that may have accumulated on high structures.

2-7 Concrete Materials.

2-7.1 Concrete used for construction of LNG containers shall be in accordance with Section 4-3.

2-7.2 Concrete structures that will be in normal or periodic contact with LNG shall be designed to withstand the design load, applicable environmental loadings, and anticipated temperature effects. Such structures include but are not limited to foundations for cryogenic equipment. They shall comply with the following:

(a) Design of the structures shall be in accordance with appropriate provisions of 4-3.2.

(b) Materials and construction shall be in accordance with the appropriate provisions of 4-3.3.

2-7.3 Pipe supports shall comply with Section 6-4.

2-7.4 All other concrete structures shall be investigated for the effects of potential contact with LNG. If failure of these structures would create a hazardous condition or worsen an existing emergency condition by exposure to LNG, the structures shall be suitably protected to minimize the effects of such exposure or they shall comply with 2-7.2(a) or (b).

2-7.5 Concrete for incidental nonstructural uses, such as slope protection and impounding area paving, shall conform to ACI 304, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*. Reinforcement shall be a minimum of 0.5 percent of the cross-sectional area of concrete for crack control in accordance with Paragraph 2-2.1 of ACI Committee Report 344, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures*.

2-7.6 Concrete that is not in constant exposure to LNG and that has been subjected to sudden and unexpected exposure to LNG shall be inspected and repaired, if necessary, as soon as practical after it has returned to ambient temperature.

Chapter 3 Process Systems

3-1 General.

3-1.1 Process system equipment containing LNG, flammable refrigerants, or flammable gases shall be either:

(a) Installed outdoors for ease of operation, to facilitate manual fire fighting, and to facilitate dispersal of accidentally released liquids and gases, or

(b) Installed indoors in enclosing structures complying with 2-3.1 and 2-3.2.

3-2 Pumps and Compressors.

3-2.1 Pumps and compressors shall be constructed of materials suitable for the temperature and pressure conditions that might be encountered.

3-2.2 Valving shall be installed so that each pump or compressor can be isolated for maintenance. Where pumps or centrifugal compressors are installed for operation in parallel, each discharge line shall be equipped with a check valve.

3-2.3 Pumps and compressors shall be provided with a pressure-relieving device on the discharge to limit the pressure to the maximum safe working pressure of the casing and downstream piping and equipment unless these are designed for the maximum discharge pressure of the pumps and compressors.

3-2.4 Each pump shall be provided with an adequate vent and/or relief valve that will prevent overpressuring the pump case during the maximum possible rate of cooldown.

3-2.5 The foundations and sumps for cryogenic pumps shall be designed and constructed to prevent frost heaving.

3-2.6 Pumps used for transfer of liquids at temperatures below -20°F (-28.9°C) shall be provided with suitable means for precooling to reduce effect of thermal shock.

3-2.7 Compression equipment handling flammable gases shall be provided with vents from all points, including distance pieces, where gases may normally escape. Vents shall be piped outside of buildings to a point of safe disposal.

3-3 Flammable Refrigerant and Flammable Liquid Storage.

3-3.1 Installation of storage tanks for flammable refrigerants and liquids shall comply with NFPA 30, *Flammable and Combustible Liquids Code*; NFPA 58, *Storage and Handling of Liquefied Petroleum Gases*; or NFPA 59, *LP-Gases at Utility Gas Plants*, or API Standard 2510, *LP-Gas Installations at Marine and Pipeline Terminals, Natural Gas Processing Plants, Refineries and Tank Farms*, as appropriate, or with Section 2-2 of this standard.

3-4 Process Equipment.

3-4.1 Process equipment shall be sited in accordance with Section 2-2.

3-4.2 Boilers shall be designed and fabricated in accordance with Section I and pressure vessels shall be designed and fabricated in accordance with Section VIII, Division 1 or Division 2, of the ASME Code, and shall be Code stamped.

3-4.3 Shell and tube heat exchangers shall be designed and fabricated in accordance with the Standards of the Tubular Exchanger Mfrs. Association (TEMA). The shells and internals of all exchangers shall be pressure tested, inspected, and stamped in accordance with Section VIII, Division 1 or Division 2, of the ASME Code, when such components fall within the jurisdiction of this Code.

3-4.4 Installation of internal combustion engines or gas turbines shall conform to NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines.*

3-4.5 A boiloff 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. Boiloff and flash gases shall discharge safely into the atmosphere or into a closed system. The boiloff venting system shall be designed so that it cannot normally inspirate air during operation.

3-4.6 If internal vacuum conditions can occur in any piping, process vessels, cold boxes, or other equipment, the facilities subject to vacuum shall be designed to withstand the vacuum conditions or provision made to prevent development in the equipment of a vacuum that might create a hazardous condition. If gas is introduced to obviate this problem, it shall be of such composition or so introduced that it will not create a flammable mixture within the system.

3-4.7 Equipment Depressurizing.[1]

3-4.7.1 Emergency controls to effect the depressurization shall be conspicuously marked with their function designated, and they shall be accessible under emergency conditions.

3-4.7.2 The discharge of flammable gases or liquids from relief devices shall be directed into a closed system or to a point of safe disposal. Flammable gases may be discharged directly to atmosphere. (*See Section 4-8.*)

3-4.8 A cold box structure and its contents shall be constructed of materials that do not support combustion.

3-4.8.1 Cold boxes shall be purged in accordance with Section 4-6, treating the cold box as a container. If a flammable mixture is detected within the cold box at any time, purge gas shall be introduced until the mixture is outside of the flammable range.

3-4.9 Salt bath heaters shall be installed within curbed areas or other means provided to retain spillage of molten salt.

3-5 Air Injection.

3-5.1 In those cases where air may have been injected into the plant inlet natural gas stream, provision shall be made to prevent a flammable mixture from occurring under any operating condition.

[1]Consideration shall be given to provisions for depressurizing equipment containing gases and liquids in case of fire or failure of the equipment (*see 9-1.2 and Section 9-10*).

3-6 Relief Devices.

3-6.1 Process equipment that can be overpressured shall be protected by safety relief valve(s) providing an effective rate of discharge. The minimum required rate of discharge shall be determined so as to prevent pressures exceeding those allowed by the governing code giving proper consideration to fire exposure, process upsets, or loss of utilities.

3-7 Process Equipment Supports.

3-7.1 Where the structural stability of process equipment is essential to plant safety, the supports for the equipment shall be resistant to or protected against fire exposure or cold liquid, or both, if they are subject to such exposures.

Chapter 4 Stationary LNG Storage Containers

4-1 General.

4-1.1 Inspection.

4-1.1.1 Prior to initial operation, containers shall be inspected to the extent necessary to assure compliance with the engineering design and material, fabrication, assembly, and test provisions of this standard. The operator shall be responsible for this inspection.

4-1.1.2 The operator may delegate performance of any part of the inspection to inspectors who may be employees of his own organization, an engineering or scientific organization, or of a recognized insurance or inspection company. Inspectors shall be qualified in accordance with the code or standard applicable to the container and as specified in this standard.

4-1.2 Basic Design Considerations.

4-1.2.1 The operator shall specify the maximum allowable working pressure, which includes a suitable margin above the operating pressure, and the maximum allowable vacuum.

4-1.2.2 Those parts of LNG containers that will normally be in contact with LNG and all materials used in contact with LNG or cold LNG vapor [vapor at a temperature below -20°F (-28.9°C)] shall be physically and chemically compatible with LNG and suitable for service at -270°F (-168°C).

4-1.2.3 All piping that is a part of an LNG container shall be in accordance with Chapter 6. This container piping shall include all piping internal to the container, within insulation spaces, within void spaces, and external piping attached or connected to the container up to the first circumferential external joint of the piping. Inert gas purge systems wholly within the insulation spaces are exempt from this provision.

4-1.2.4 All LNG containers shall be designed to accommodate both top and bottom filling unless other positive means are provided to prevent stratification. (*See 8-1.3.*)

4-1.2.5 Any portion of the outer surface area of an LNG container that could be accidentally exposed to low temperatures resulting from leakage of LNG or cold vapor from flanges, valves, seals, or other nonwelded connections shall be suitable for such temperatures or otherwise protected from the effects of such exposure.

4-1.2.6 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.

4-1.2.7 The density of the liquid shall be assumed as the actual weight per cu ft (cu m) at the minimum storage temperatures except that in no case will the density assumed be less than 29.3 lbs/ft^3 (470 kg/m^3).

4-1.2.8 The design shall consider the requirements for taking the LNG container out of service.

4-1.3 Seismic Design.

4-1.3.1 Seismic loads shall be considered in the design. (*See Chapter 6, "Dynamic Pressure on Fluid Containers," of Nuclear Reactors and Earthquakes, TID-7024, National Technical Information Service, for further information.*) The operator shall perform a site investigation to determine the seismic potential and resulting response spectra for all installations except those provided for in 4-1.3.7. Investigations shall be conducted to obtain pertinent geotechnical information concerning the geologic and seismic characteristics of the LNG facility and the surrounding region.

4-1.3.2 The investigation shall include:

(a) The detection and identification of surface faulting as appropriate at the specific site and the potential for such faulting.

(b) The characteristics of the materials underlying the site as they relate to the transmission of vibratory motion from bedrock through the soil if the facility is not grounded on rock as well as the potential for soil liquefaction and degradation.

(c) Determination of vertical and horizontal response spectra correlating the acceleration, velocity, and displacement with the seismic characteristics of the soil and damping factors of the structural systems in the range of anticipated natural periods of vibration.

4-1.3.3 The investigation shall determine the Safe Shutdown Earthquake (SSE) and Operating Basis Earthquake (OBE), which shall be defined:

(a) Probabilistically, as those that produce ground motions with a mean recurrence interval of 10,000 years for the SSE and 475 years for the OBE, or

(b) In regions where the uncertainties are difficult to quantify because of the lack of geological data, using a deterministic approach, where the SSE is the event that produces the maximum credible ground motion at the site based upon the seismology, geology, seismic and geologic history of the site and region, and where the ground motions for the OBE shall be one-half those determined for the SSE.

4-1.3.4 The following structures and systems shall be designed to comply with 4-1.3.3:

(a) An LNG container and its impounding system

(b) System components required to isolate the LNG container and maintain it in a safe shutdown condition

(c) Fire protection systems.

4-1.3.5 An LNG container shall be designed for the OBE and a stress limit check made for the SSE. Stresses for the OBE shall be in accordance with the code or standard applicable to the container as specified in this standard. Stress limits for the SSE shall not exceed yield for the tensile condition and critical for the buckling condition when including the effect of liquid pressure on buckling stability.

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

4-1.3.6 The dynamic analysis of the LNG container and associated structural components shall include the effects of liquid sloshing and restrained liquid.[1] Tank flexibility, including shear deformation, shall be included in determination of the significant tank frequencies. For containers supported by pile caps, the flexibility of the pile system shall be considered.

4-1.3.7 Shop-built containers designed and constructed in accordance with the ASME Code, and their support system, shall be designed for the horizontal seismic accelerations in Table 4-1 and for vertical accelerations of two-thirds of these values. Zones shall be determined from ANSI A58.1, *Minimum Design Loads for Buildings and Other Structures.*

Table 4-1 Seismic Accelerations for Shop-built Containers

Zone	%G
0	2
1	7
2	15
3	28
4	As determined by investigation in accordance with 4-1.3.1 and 4-1.3.2

4-1.4 Wind and Snow Loads.

4-1.4.1 The wind and snow loads for the design of LNG storage containers shall be determined using the procedures outlined in ANSI A58.1, *Building Code Requirements for Minimum Design Loads in Buildings and Other Structures.* Where a probabilistic approach is appropriate, a 100-year mean occurrence interval shall be used.

4-1.5 Container Insulation.

4-1.5.1 Any exposed insulation shall be noncombustible, shall contain or inherently shall be a vapor barrier, shall be water free, and shall resist dislodgement by fire hose streams. When an outer shell is used to retain loose insulation, the shell shall be constructed of steel or concrete. Exposed weatherproofing shall have a flame spread rating not greater than 25 (*see definition of Flame Spread Rating*).

4.1.5.2 The space between the inner tank and the outer tank shall contain insulation that is compatible with LNG and natural gas and is noncombustible. The insulation shall be such that a fire external to the outer tank will not cause significant deterioration to the insulation thermal conductivity by melting, settling, etc.

Exception: Materials used between the inner and outer tank bottoms (floors) only do not have to meet the combustibility requirements if the material and the design of the installation comply with all of the following:

(1) The flame spread rating of the material shall not exceed 25, and the material shall not support continued progressive combustion in air, and

(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 rating not greater than 25 and shall not support continued progressive combustion, and

(3) The combustion properties of the material shall be shown by test to not significantly increase as a result of long term exposure to LNG or natural gas at the anticipated service pressure and temperature, and

(4) The materials in the installed condition shall be demonstrated to be capable of being purged of natural gas remaining after purging is not significant and does not increase the combustibility of the material.

4-1.6 Filling Volume.

4-1.6.1 The maximum filling volume of an LNG container shall be in accordance with Figure 4-1. The liquid capacity is the volume of liquid to its maximum permissible level.

NOTE 1: After filling a container, the gas pressure may be less than the maximum allowable working pressure. Expansion of the liquid will occur when the liquid subsequently warms and the pressure rises to the maximum allowable working pressure. The operator shall limit the maximum filling volume as indicated by Figure 4-1 to avoid overfilling when this expansion occurs.

NOTE 2: For containers with maximum allowable working pressures less than about 2 psig (about 14 kPa) the correction for maximum filling volume is negligible and may be omitted.

4-1.7 Foundations.

4-1.7.1 LNG containers shall be installed on suitable foundations designed by a qualified engineer and constructed in accordance with recognized structural engineering practices. Prior to the start of design and construction of the foundation, a sub-surface investigation shall be conducted by a qualified soils engineer to determine the stratigraphy and physical properties of the soils underlying the site. (*See ASCE 56, Sub-Surface Investigation for Design and Construction of Foundation for Buildings, and Appendix C, API Standard 620, for further information.*)

[1]For the background theory on the response of fluid containers to seismic loads, reference may be made to Chapter 6, "Dynamic Pressure on Fluid Containers," of *Nuclear Reactors and Earthquakes*, TID-7024, National Technical Information Service.

This document may also be used to calculate the sloshing height of the liquid surface.

4-1.7.2 The bottom of the outer tank shall be above the ground water table or otherwise protected from contact with ground water at all times, and the material in contact with the bottom of the outer tank shall be selected to minimize corrosion.

4-1.7.3 When 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. The heating system shall be designed so as to permit functional and performance monitoring, which shall be done, at a minimum, on a weekly basis. Where there is a discontinuity in the foundation, such as for bottom piping, careful attention and separate treatment shall be given to the heating system in this zone. Heating systems shall be installed so that any heating element or temperature sensor used for control can be replaced. Provisions shall be incorporated to protect against the detrimental effects of moisture accumulation in the conduit, which could result in galvanic corrision or other forms of deterioration within the conduit or heating element.

4-1.7.4 If the foundation is installed to provide adequate air circulation in lieu of a heating system, then the bottom of the outer tank shall be of a material suitable for the temperatures to which it will be exposed.

4-1.7.5 The LNG container foundation shall be periodically monitored for settlement during the life of the facility including construction, hydrostatic testing, commissioning, and operation. Any settlement in excess of that anticipated in the design shall be investigated and corrective action taken if appropriate.

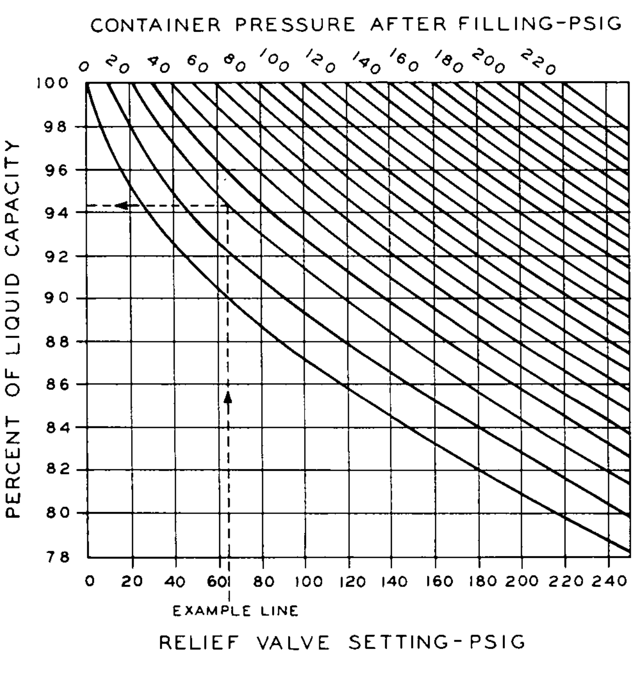

Figure 4-1 Maximum filling volume for pressure containers.

Example: A container designed for a maximum allowable working pressure of 65 psig has the relief valve set at 65 psig. After filling, the gas pressure at the top is 20 psig. From the chart, the maximum filling volume is 94.3 percent of the liquid capacity.

4-2 Metal Containers.

4-2.1 Containers Designed for Operation at 15 Psig (103 kPa) and Less.

4-2.1.1 Welded containers designed for not more than 15 psig (103 kPa) shall comply with API 620. Appendix Q of API 620 shall be applicable for LNG with the following changes:

(a) In paragraph Q-7.6.5 change "twenty-five percent" to "all."

(b) In paragraph Q-7.6.1thru Q-7.6.4 100 percent radiographic inspection of all vertical and horizontal butt welds associated with the container wall shall be required:

Exception: The shell-to-bottom welds associated with a flat bottom container are exempt from this radiographic inspection requirement.

(c) Paragraph C-11 shall be a mandatory requirement.

4-2.2 Containers Designed for Operation at More than 15 Psig (103 kPa).

4-2.2.1 Containers may be double-walled with the inner tank holding the LNG surrounded by insulation contained within the outer tank. The insulation may be evacuated or purged.

4-2.2.2 The inner tank shall be of welded construction and shall conform to the provisions of Section VIII, Division 1, of the ASME Code and shall be stamped and registered with the National Board of Boiler and Pressure Vessel Inspectors.

(a) Any of the materials authorized for -270°F (-168°C) service by the ASME Code are acceptable.

(b) In the case of vacuum insulation, the design pressure shall be the sum of the required working pressure, 15 psig (103 kPa) for vacuum allowance, and the hydrostatic head of LNG. In the case of nonvacuum insulation, 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 leading resulting from internal pressure as the tank expands after an inservice period, the purging and operating pressure of the space between the inner and outer tanks, and seismic loads.

4-2.2.3 The outer tank shall be of welded construction.

(a) Any of the carbon steels authorized in the UCS Section of the ASME Code are acceptable if suitable for the lowest anticipated ambient temperatures.

(b) In the case of vacuum insulation, the outer tank shell shall be designed by the procedures outlined in UG-28, UG-29 and UG-30 of the ASME Code using an external pressure of not less than 7.5 psi (52 kPa) (differential). Spun heads that meet the tolerance provision of UG-81 may be designed by the procedures outlined in UG-33 of the ASME Code using an external pressure of not less than 7.5 psi (52 kPa).Heads and spherical outer tanks that are formed in segments and are assembled by welding shall be designed using an external pressure of 15 psi (103 kPa).

(c) The outer tank shall be designed for the most critical combination of loadings resulting from the structural support of the inner tank and its contents, the static insulation pressure, the insulation pressure as the tank expands after an inservice period, the pressure from wind forces and the roof loading, the purging and operating pressure of the space between the inner and outer tank, and seismic forces.

(d) The outer tank shall be equipped with a relief device or other device to release internal pressure. The discharge area must be at least 0.00024 sq in./lb (0.0034 sq cm/kg) of the water capacity of the inner tank but the area need not exceed 300 sq in. (2000 sq cm). Such a device must 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 less.

(e) When it is possible that the outer tank temperature may go below its design temperature because of conduction from cold lines, thermal barriers shall be provided between the lines and the outer tank.

(f) Saddles and legs shall be designed in accord with recognized structural engineering practices. Consideration shall be given to shipping loads, erection loads, seismic loads, wind loads, and thermal loads.

(g) Foundations and supports shall be protected to have a fire resistance rating of not less than 2 hours. If insulation is used to achieve this requirement it shall be resistant to dislodgement by fire hose streams.

4-2.2.4 Stress concentrations from the support system shall be minimized by the use of pads, load rings, etc. Consideration shall be given to the expansion and contraction of the inner tank, and the support system shall be so designed that resulting stresses imparted to the inner and outer tanks are within acceptable limits.

4-2.2.5 Internal lines (those between the inner tank and the outer tank and within the insulation space) shall be designed for the pressure rating of the inner tank with allowance for the thermal stresses created by the -270°F (-168°C) temperature including both line contraction and contraction movement of the inner tank. No bellows are permissible within the insulation space.

(a) Lines shall be of materials satisfactory for -270°F (-168°C) as determined by the ASME Code. No liquid line external to the outer tank shall be of aluminum or copper or a copper alloy unless protected against a 2-hour fire exposure. Transition joints may be used.

4-2.2.6 The inner tank shall be supported essentially concentrically within the outer tank by either a metallic or a nonmetallic system that is capable of sustaining the maximum loading of 4-2.2.7(a) or (b).

(a) For shipping load, the supports shall be designed for the maximum number of G's (*see definition*) to be encountered multiplied by the empty weight of the inner tank.

(b) For operating load, the supports shall be designed for the total weight of the inner tank and contents. Appropriate seismic factors shall be included. The weight of contained liquid shall be based upon the maximum density of the specified liquid within the range of operating temperatures, except that the minimum density shall be at least 29.3 lbs/ft^3 (470 kg/m^3).

4-2.2.7 The allowable design stress in inner tank support members shall be the lesser of $1/3$ the tensile strength or $5/8$ of the yield strength at room temperature. For threaded members the minimum area at the root of the threads shall be used.

4-3 Concrete Containers.

4-3.1 Scope. This section applies to the design and construction of prestressed concrete containers for any operating pressure, whether externally or internally insulated, and for prestressed concrete protective walls surrounding any type of container.

4-3.2 Container Structure.

4-3.2.1 Design of the concrete containers shall comply with American Concrete Institute standard, ACI 318, *Building Code Requirements for Reinforced Concrete*, and the provisions of ACI Committee Report 344, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures*, and shall be in accordance with 4-3.2.2, 4-3.2.3, and 4-3.2.4.

4-3.2.2 Allowable stresses for normal design considerations shall be based upon room temperature strength values.

4-3.2.3 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 following allowable stresses:

#4 and smaller	–	12,000 psi (82.7 MPa)
#5, #6 and #7	–	10,000 psi (68.9 MPa)
#8 and larger	–	8,000 psi (55.2 MPa)

Tensile stresses inclusive of direct temperature and shrinkage effects shall not exceed the yield strength of the reinforcement.

4-3.2.4 Steel wire or strands as specified in 4-3.3.4 and used as unstressed reinforcement shall be designed with a maximum allowable stress as follows:

Crack control applications	–	30,000 psi (206.8 MPa)
Other applications	–	80,000 psi (552 MPa)

4-3.2.5 External forces imposed upon the container by backfill restraint during warmup shall be considered.

4-3.3 Materials Subject to LNG Temperature.

4-3.3.1 Concrete shall be as specified by ACI 304, *Guide for Measuring, Mixing, Transportation and Placing of Concrete*; and ACI 318, *Building Code Requirements for Reinforced Concrete*; concerning construction requirements, specifications, and tests.

Tests 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.

4-3.3.2 Aggregate shall be as specified by ASTM C33, *Specification for Concrete Aggregates*. Aggregate shall be dense and physically and chemically sound to provide a high strength and durable concrete.

4-3.3.3 Pneumatic Mortar shall be as specified in ACI 506, *Guide for Shotcreting*.

4-3.3.4 High tensile strength elements for prestressed concrete shall be as specified by ASTM A227, *Specification for Steel Wire, Hard Drawn for Mechanical Springs*; ASTM A-421, *Standard Specification for Uncoated Stress-Relieved Wire for Prestressed*

Concrete; ASTM A416, *Standard Specification for Steel Strand Uncoated Seven-Wire Stress Relieved Strand for Prestressed Concrete*; and ASTM A821, *Specification for Steel Wire, Hard Drawn for Prestressed Concrete Tanks*. In addition, any material acceptable for service at LNG temperature, such as those materials specified for "Primary components" in API 620, or any material shown by test to be acceptable for LNG service may be used.

Material for permanent end anchorages shall be suitable for service at LNG temperatures.

4-3.3.5 Reinforcing steel for reinforced concrete shall be as specified in ASTM A82, *Standard Specification for Steel Wire, Plain, for Concrete Reinforcement*; ASTM A185, *Standard Specification for Welded Steel Wire, Fabric, Plain, for Concrete Reinforcement*; and ASTM A615, *Standard Specification for Deformed and Plain Billet-Steel Bars for Concrete Reinforcement* (Grades 40 and 60 only).

4-3.3.6 Nonstructuralmetallic 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 Appendix Q, API 620, providing that the composite section is prestressed such that no significant tensile stresses are developed under any design loading condition.

4-3.3.7 Nonstructural metallic barriers incorporated in and functioning compositely with prestressed concrete and serving primarily as moisture barriers for internally insulated tanks shall be of metal classified for either "Primary component" or "Secondary component" service in Appendix Q, API 620 or of steel conforming to ASTM A366, *Standard Specification for Steel, Sheet, Carbon, Cold-Rolled, Commercial Quality*, providing that the composite section is prestressed so that no significant tensile stresses are developed under any design loading condition.

4-3.4 Construction, Inspection, and Tests.

4-3.4.1 Concrete LNG containers shall be built in accordance with the applicable provisions of ACI 318, *Building Code Requirements for Reinforced Concrete*, and ACI Committee Report 344, *Design and Construction of Circular Wire and Strand Wrapped Prestressed Concrete Structures*.

4-3.4.2 Concrete LNG containers shall be inspected in accordance with ACI 311, *Guide for Concrete Inspection and Section 4-5*.

4-3.4.3 Metal components shall be constructed and tested in accordance with the applicable provisions in Appendix Q, API 620.

4-3.4.4 Other materials used in the construction of concrete LNG containers shall be subjected to suitable inspection and tests.

4-4 Marking of LNG Containers.

4-4.1 Each container shall be identified by the attachment of a nameplate in an accessible place marked with the following information:

(a) Builder's name and date built

(b) Nominal liquid capacity; barrels, gallons, or cubic meters

(c) Design pressure in appropriate units for methane gas at top of container

(d) Maximum permissible density of liquid to be stored

(e) Maximum level to which container may be filled with stored liquid (*see 4-1.6.1*)

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

(g) Minimum temperature in degrees Fahrenheit or Celsius for which the container was designed.

4-4.2 Storage containers shall have all penetrations marked with the function of the penetration. Consideration shall be given to "frosting" and identification shall not be lost from such effect.

4-5 Testing of LNG Containers.

4-5.1 LNG containers shall be leak tested by a method appropriate to the design, construction, and operating pressure of the container and in accordance with the governing construction code or standard. All leaks shall be repaired.

4-5.1.1 Inspection shall be performed in accordance with the Inspection and Tests section of the applicable construction code.

NOTE: If no specific single code is applicable the equivalent of API 620 should be applied for containers designed for 15 psig (103 kPa) and under and of the ASME Code for containers designed for over 15 psig (103 kPa) design pressure.

4-5.1.2 Shop fabricated and tested LNG containers shall be leak tested to a minimum of the design pressure after installation and prior to filling the container with LNG.

4-5.1.3 For vacuum insulation, the inner tank, outer tank, and internal lines shall be tested for vacuum leaks by an appropriate procedure.

4-5.2 After acceptance tests are completed, there shall be no field welding on the LNG containers except upon saddle plates or brackets provided for the purpose unless such repairs or modifications comply with the code or standard under which the container was originally fabricated. Retesting by a method appropriate to the repair or modification shall be required only when the repair or modification is of such a nature that a retest will actually test the element affected and is necessary to demonstrate the adequacy of the repair or modification.

4-6 Container Purging Procedures.

4-6.1 There are several methods used for purging large vessels into and out of service. This standard does not restrict constructors or operators to any one technique but cautions that only experienced and qualified personnel shall be responsible for such activities.

NOTE: There are several references covering the purging of large vessels, two of which are American Gas Association's Gas Engineer's Handbook and Purging, Principles and Practice.

4-6.2 Prior to placing an LNG container into service the air must be displaced by an acceptable inerting procedure.

4-6.3 Prior to taking a container out of service, the natural gas in the container shall be purged from the container in a safe manner by an acceptable inerting procedure.

NOTE: 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.

4-6.4 During purging operations, the oxygen content of the container shall be determined by the use of an acceptable oxygen analyzer.

4-7 Cooldown Procedure.

4-7.1 Cooldown of an LNG container shall be limited to a rate and distribution pattern that will assure thermal stresses are within allowable limits during the cooldown period.

4-7.2 During initial cooldown of the tank particular attention shall be given to tank penetrations to ensure proper performance of expansion bends or joints.

4-8 Pressure and Vacuum Control.

4-8.1 Provision shall be made to maintain the internal pressure and vacuum of LNG containers within the limits set by the design specifications by releasing or admitting gas as needed. Factors that shall be considered in sizing such pressure control means shall include:

4-8.1.1 For pressure:

(a) Loss of refrigeration

(b) Operational upset, such as failure of a control device

(c) Vapor displacement and flash vaporization during filling, as a result of filling, and as a consequence of controlled mixing of LNG of different compositions (which can result from weathering) and/or temperatures

(d) Drop in barometric pressure

(e) Flash vaporization resulting from pump recirculation.

4-8.1.2 For vacuum:

(a) Withdrawal of liquid at the maximum rate

(b) Withdrawal of vapor at the maximum compressor suction rate

(c) Rise in barometric pressure

(d) Reduction in vapor pressure resulting from the introduction of subcooled LNG into the vapor space.

4-8.2 Provision for admission and release of gas required in 4-8.1 may be by any means compatible with the gas-handling facilities in the plant.

4-8.3 In addition to the pressure control means provided for in 4-8.1, LNG containers shall be equipped with adequate direct acting pressure relief valves and vacuum relief valves (vacuum breakers) communicating directly with the atmosphere and having capacities calculated for any likely combination of the factors listed in 4-8.1.1 and 4-8.1.2. The option of gas admission through the vacuum relief valves, provided by 6.02.3 in API 620, shall not be permitted. Pressure relief valves shall also consider discharge that can accompany fire exposure. As a minimum, 4-8.3.1, 4-8.3.2, and 4-8.3.3 shall apply.

4-8.3.1 When a container is exposed to an open fire, heat is transferred to the stored liquid. Additional heat is simultaneously transferred through the parts of the container not exposed to fire due to the high difference between the normal ambient temperature and the stored liquid temperature. The minimum total heat influx during a possible fire exposure of an insulated container shall be computed by the formula:

$$H = 1560\ C_1A^{0.82} + H_\eta$$

where

H = Total heat influx, Btu per hour

C^1 = Conductance of the insulation, Btu/sq ft – hr – °F. (The value of C increases with temperature and a mean value for the range from -260° and +1660°F should be used.)

A = Total exposed wetted surface area in sq ft.

H_n = Total normal heat gain to the stored liquid without fire exposures and at maximum ambient temperatures, Btu per hour.

4-8.3.2 If the insulation system, including any jacketing material, is such that it will disappear, deteriorate, or dislodge in an exposure fire, a higher heat gain will occur. This requires special consideration depending upon the extent of loss of the insulating properties. If only a part of the insulation is lost, the heat gain may be estimated by the formula:

$$H = (34{,}500 - 360\ C_2)\ A^{0.82} + H_n$$

In this case the value of C_2 should be the mean value for the range from -260°F and + 100°F.

4-8.3.3 The required relief valve capacity shall be computed by the formula:

$$Q = 3.09\ \frac{H}{L}\sqrt{\frac{T}{M}}$$

Q_n = Required flow capacity of air, cu ft per hour at 60°F and 14.7 psia

H = Total heat influx, Btu per hour from Formula A-1 or A-2

L = Latent heat of vaporization of the stored liquid, Btu per lb

T = Absolute temperature of the gas at the relief valve inlet, °R

M = Molecular weight of the gas.

4-8.4 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. This stop valve (or valves) shall be lockable or sealable in the full open position. Sufficient pressure and vacuum relief valves shall be installed on the LNG container to allow each relief valve to be individually isolated for testing or maintenance while maintaining the full capacities determined in 4-8.3. When only one relief device is required, a full port opening three-way valve may be used under the relief device and its required spare in lieu of individual valves beneath each relief device.

4-8.4.1 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.

4-8.4.2 No more than one stop valve shall be closed at one time, thus maintaining the relief capacity of 4-8.3.

4-8.5 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 upwards.

Chapter 5 Vaporization Facilities

5-1 Classification of Vaporizers.

5-1.1 Heated Vaporizers shall be classified as those vaporizers that derive their heat from the combustion of fuel, electric power, or waste heat, such as from boilers or internal combustion engines.

5-1.1.1 Integral Heated Vaporizers shall be classified as those heated vaporizers in which the heat source is integral to the actual vaporizing exchanger. This classification includes submerged combustion vaporizers.

5-1.1.2 Remote Heated Vaporizers shall be classified as those heated vaporizers in which the primary heat source is separated from the actual vaporizing exchanger, and an intermediate fluid (e.g., water, steam, isopentane, glycol, etc.) is used as the heat transport medium.

5-1.2 Ambient Vaporizers shall be classified as those vaporizers that derive their heat from naturally occurring heat sources, such as the atmosphere, sea water, or geothermal waters. If the naturally occurring heat source 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.

5-1.3 Process Vaporizers shall be classified as those vaporizers that derive their heat from another thermodynamic or chemical process or in such a fashion as to conserve or utilize the refrigeration from the LNG.

5-2 Design and Materials of Construction.

5-2.1 Vaporizers shall be designed, fabricated, and inspected in accordance with Section VIII, Division 1 of the ASME Code. Because these vaporizers operate over a temperature range of -260°F to + 100°F (-162°C to + 38°C) the rules of Section I of the ASME Code, Part PVG, are not applicable.

5-2.2 Vaporizer heat exchangers shall be designed for a working pressure at least equal to the maximum discharge pressure of the LNG pump or pressurized container system supplying them, whichever is greater.

5-3 Vaporizer Piping and Intermediate Fluid Piping and Storage.

5-3.1 Manifolded vaporizers shall have both inlet and discharge block valves at each vaporizer.

5-3.2 The discharge valve of each vaporizer, piping components, and relief valves installed upstream of that valve shall be suitable for operation at LNG temperatures [-260°F (-162°C)].

5-3.3 Suitable automatic equipment shall be provided to prevent the discharge of either LNG or vaporized gas into a distribution system at a temperature either above or below the design temperatures of the sendout system. Such automatic equipment shall be independent of all other flow control systems and shall incorporate a line valve(s) used only for emergency purposes.

5-3.3.1 Isolation of an idle manifolded vaporizer to prevent leakage of LNG into that vaporizer shall be accomplished with two inlet valves, and a safe means shall be provided to dispose of the LNG or gas that may accumulate between the valves. Ambient vaporizers having inlets 2 in. in size or less need not comply with this provision.

5-3.4 Each heated vaporizer shall be provided with a means to shut off the heat source from a location at least 50 ft (15 m) distant from the vaporizer. The device shall also be operable at its installed location.

5-3.5 A shutoff valve shall be installed on the LNG line to a heated vaporizer at least 50 ft (15 m) from the vaporizer except when the vaporizer is closer than 50 ft (15 m) to the container from which it is supplied (*see 2-2.5.4*), in which case the provisions of 5-3.6 apply. If the vaporizer is installed in a building, the shutoff valve shall be installed at least 50 ft (15 m) from the building. This may be the valve provided for in 6-3.3.2.

5-3.5.1 This shutoff valve shall be operable either at its installed location or from a remote location, and the valve shall be protected from becoming inoperable due to external icing conditions.

5-3.6 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. This valve shall be located at least 10 ft (3 m) from the vaporizer and shall close on loss of line pressure (excess flow), on abnormal temperature sensed in the immediate vicinity of the vaporizer (fire), or low temperature in the vaporizer discharge line. At attended facilities, remote operation of this valve from a point at least 50 ft (15 m) from the vaporizer is acceptable.

5-3.7 If a flammable intermediate fluid is used with a Remote Heated Vaporizer, shutoff valves shall be provided on both the hot and cold lines of the intermediate fluid system. The controls for these valves shall be located at least 50 ft (15 m) from the vaporizer.

5-4 Relief Devices on Vaporizers.

5-4.1 Each vaporizer shall be provided with a safety relief valve(s) sized in accordance with 5-4.1.1 or 5-4.1.2 as applicable.

5-4.1.1 The relief valve capacity of heated or process vaporizers shall be such that the relief valve(s) will discharge 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.

5-4.1.2 The relief valve capacity for ambient vaporizers shall be such that the relief valve(s) will discharge at least 150 percent of rated vaporizer natural gas flow capacity (as stated for standard operating conditions) without allowing the pressure to rise more than 10 percent above the vaporizer maximum allowable working pressure.

5-4.2 Relief valves on heated vaporizers shall be so located that they are not subjected to temperature exceeding 140°F (60°C) during normal operation unless designed to withstand higher temperatures.

5-5 Combustion Air Supply.

5-5.1 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.

5-6 Products of Combustion.

5-6.1 When integral heated vaporizers or the primary heat source for remote heated vaporizers are installed in buildings, consideration shall be given to the prevention of an accumulation of hazardous products of combustion.

Chapter 6 Piping Systems and Components

6-1 General.

6-1.1 All piping systems shall be in accordance with ANSI B31.3, *Chemical Plant and Petroleum Refinery Piping*. The additional provisions of this chapter shall apply only to pressurized piping systems and components for LNG, flammable refrigerants, flammable liquids, and flammable gases and unpressurized or low pressure piping systems, including vent lines and drain lines, which handle LNG, flammable refrigerants, flammable liquids, and flammable gases with service temperatures below -20°F (-29°C).

6-1.2 Seismic loads shall be considered in the piping design. Results of the seismic study of 4-1.3, or the accelerations in Table 4-1 as applicable, shall be used to determine the forces that would be applicable to the piping design. The longitudinal stresses, which are developed in this analysis, shall meet the requirements of 302.3.6(a) of ANSI B31.3. Container associated piping up to and including the first container shutoff valve in LNG lines shall be designed to meet the provisions of 4-1.3.4(b).

6-1.3 Piping systems and components shall be designed to accommodate the effects of fatigue resulting from the thermal cycling to which the systems will be subjected. Particular consideration shall be given where changes in size or wall thickness occur between pipes, fittings, valves, and components.

6-1.4 Provision for expansion and contraction of piping and piping joints due to temperature changes shall be in accordance with 319 of ANSI B31.3.

6-2 Materials of Construction.

6-2.1 General.

6-2.1.1 All piping materials, including gaskets and thread compounds, shall be suitable for use with the liquids and gases handled throughout the range of temperatures to which they will be subjected. The temperature limitations for pipe materials shall be as specified in ANSI B31.3.

6-2.1.2 Piping that would be exposed to the cold of an LNG or refrigerant spill or the heat of an ignited spill during an emergency when such exposure could result in a failure of the piping that would significantly increase the emergency shall be:

(a) Made of material(s) that is suitable for both its normal operating temperature and the extreme temperature that it might be subjected to during the emergency or

(b) Protected by insulation or other means to delay failure due to such extreme temperatures until corrective action may be taken by the operator or

(c) Capable of being isolated and flow stopped in piping that would be exposed only to the heat of an ignited spill during the emergency.

6-2.1.3 Piping insulation used in areas where the mitigation of fire exposure is necessary shall be made of material(s) that will not 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, as applicable.

6-2.2 Piping.

6-2.2.1 Furnace lap-weld and furnace butt-weld pipe shall not be used. When longitudinal or spiral weld pipe is used (welded with or without filler metal), the weld and heat affected zone shall comply with 323.2.2 of ANSI B31.3 (*see 6-6.3, 6-6.4, 6-6.5, and 6-6.6*).

6-2.2.2 Threaded pipe shall be at least Schedule 80 (*see 6-3.2.1 and 6-3.2.2*).

6-2.2.3 A liquid line on a storage container, cold box, or other major item of 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 other material that has low resistance to flame temperatures unless protected against fire exposure. This does not apply to loading arms and hoses. Transition joints may be used if protected against fire exposure as indicated.

6-2.2.4 Cast, malleable, and ductile iron pipe shall not be used.

6-2.3 Fittings.

6-2.3.1 Threaded nipples shall be at least Schedule 80.

6-2.3.2 Cast, malleable, and ductile iron fittings shall not be used.

| **6-2.3.3** Bends are permitted only in accordance with 332 ANSI B31.3.

6-2.3.4 Solid plugs or bull plugs made of at least Schedule 80 seamless pipe shall be used for threaded plugs.

6-2.3.5 Compression-type couplings shall not be used where they will be subjected to temperatures below -20°F (-29.9°C) unless such couplings meet the requirements of 318 of ANSI B31.3.

6-2.4 Valves.[1]

6-2.4.1 In addition to complying with ANSI B31.3, Section 307, valves shall comply with ANSI B31.5, *Refrigeration Piping*, or ANSI B31.8, *Gas Transmission and Distribution Piping*, or API Standard 6D, *Specification for Pipeline Valves*, if design conditions fall within their scope.

6-2.4.2 Cast, malleable, and ductile iron valves shall not be used.

6-3 Installation.

6-3.1 Bolted Connections.

6-3.1.1 Care shall be taken to ensure the tightness of all bolted connections. Spring washers or other such devices designed to compensate for the contraction and expansion of bolted connections during operating cycles shall be used where required.

6-3.2 Piping Joints.

6-3.2.1 Pipe joints of 2 in. nominal diameter or less may be threaded, welded, or flanged. Pipe joints larger than 2 in. nominal diameter shall be welded or flanged, except that joints of 4 in. nominal diameter or less may be threaded where necessary for special connections to equipment or components provided that such special connection is not subject to fatigue-producing stresses.

[1]Extended bonnet valves with or without bellows seals should be used for servce temperatures below -50°F (-45.6°C).

6-3.2.2 The number of threaded or flanged joints shall be kept to a minimum and used only where necessary, such as at material transitions, instrument connections, or where required for maintenance. If threaded joints are unavoidable, they shall be seal-welded or sealed by other means proven by test.

6-3.2.3 Metals may be joined for cryogenic service by silver brazing. Silver brazing may be used in joining copper to itself, to copper alloys, and to stainless steel. Dissimilar metals may be joined by flanges or transition joint techniques that have been proven by test.

6-3.2.4 The selection of gasket material shall include the consideration of exposure to fire.

6-3.3 Valves.

6-3.3.1 Extended bonnet valves shall be installed with packing seals in such a position as to prevent leakage or malfunction due to freezing. If the extended bonnet in a cryogenic liquid line is installed at an angle greater than 45 degrees from the upright vertical position, evidence of satisfactory service in the installed position shall be demonstrated.

6-3.3.2 Shutoff valves shall be provided on container, tank, and vessel connections, except connections:

(a) For relief valves [shutoff valves are only permitted at connections for relief valves in accordance with Section VIII, Division 1, of the ASME Code, Paragraphs UG-125(d) and Appendix M, Paragraphs M-5 and M-6]

(b) For liquid level alarm required by 7-1.1.2

(c) That are blind flanged or plugged.

Shutoff valves shall be located as close as practicable to such containers, tanks, and vessels and shall be located inside the impounding area.

6-3.3.3 The design and installation of an internal valve shall be such that any failure of the penetrating nozzle resulting from external pipe strain will be beyond the shutoff seats of the internal valve itself.

6-3.3.4 The number of shutoff valves installed shall be kept to the minimum required for efficient and safe operation.

6-3.3.5 In the design of the piping system, consideration shall be given to the installation of shutoff or block valves as a means of limiting the contained volume that could be discharged in the event of a piping system failure. The following valving shall be provided:

(a) Sufficient valves, which can be operated both at the installed location and from a remote location, to permit shutting down the process and transfer systems by systems, areas, or totally in the event of an emergency.

(b) In addition to the provisions of 6-3.3.2, container connections larger than 1 in. in size 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 shall remain closed except during the operating period

(3) A check valve on filling connections.

6-3.3.6 Valves and valve controls shall be designed to permit operation under icing conditions if such conditions can exist.

6-3.3.7 Powered operators shall be provided for emergency shutoff valves that would require excessive time to operate during an emergency or if the valve is 8 in. or larger in size. Means for manual operation shall be provided.

6-3.4 Welding.

6-3.4.1 Qualification and performance of welders shall be in accordance with 328.2 of ANSI B31.3, and 6-3.4.2.

6-3.4.2 When welding impact-tested materials, qualified welding procedures shall be selected to minimize degradation of the low temperature properties of the pipe material.

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

6-3.4.3 Oxygen-fuel gas welding shall not be permitted on piping for service temperatures below -20°F (-28.9°C). Electric arc or inert gas-shielded welding is permissible.

6-3.5 Pipe Marking.

6-3.5.1 Markings on pipe shall comply with 6-3.5.2 and 6-3.5.3.

6-3.5.2 Markings shall be made with a material compatible with the basic material or with a round-bottom, low-stress die, except that materials less than 1/4 in. (6.35 mm) in thickness shall not be die-stamped.

6-3.5.3 Marking materials that are corrosive to the pipe material shall not be used. Under some conditions marking materials containing carbon or heavy metals can cause corrosion of aluminum. Marking materials containing chloride or sulphur compounds cause corrosion of some stainless steels. Chalk, wax-base crayons, or marking inks with organic coloring are satisfactory.

6-4 Pipe Supports.

6-4.1 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 or escaping cold liquid, or both, if they are subject to such exposure.

6-4.2 Pipe supports for cold lines shall be designed to prevent excessive heat transfer, which can result in piping restraints caused by ice formations or embrittlement of supporting steel. Design of supporting elements shall conform to 321 of ANSI B31.3.

6-5 Piping Identification.

6-5.1 Piping shall be identified by color-coding, painting, or labelling. ANSI A13.1, *Scheme for the Identification of Piping Systems* may be used as a guide (*see 6-3.5.3*).

Any existing company color code scheme for the identification of piping systems may be used.

6-6 Inspection and Testing of Piping.

6-6.1 Pressure tests shall be conducted in accordance with 345 of ANSI B31.3. 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.

6-6.2 Records of pressure, test medium temperature, and ambient temperature shall be maintained for the duration of each test, and these records shall be maintained for the life of the facility or until such time as a retest is conducted.

6-6.3 Welded Pipe Tests.

6-6.3.1 Longitudinal or spiral welded pipe that will be subjected to service temperatures below -20°F (-28.9°C) shall have a design pressure of less than 2/3 of the mill proof test pressure or subsequent shop or field hydrostatic test pressure except for pipe that has been subjected to 100 percent radiographic or ultrasonic inspection of the longitudinal or spiral weld.

6-6.3.2 All circumferential butt-welds shall be fully examined by radiographic or ultrasonic inspection, except that liquid drain and vapor vent piping with an operating pressure that produces a hoop stress of less than 20 percent specified minimum yield stress need not be nondestructively tested provided it has been visually inspected in accordance with 344.2 of ANSI B31.3.

6-6.3.3 All socket welds and fillet welds shall be fully examined by liquid penetrant or magnetic particle inspection.

6-6.3.4 All fully penetrated groove welds for branch connections (as required by 328.5.4 of ANSI B31.3) shall be fully examined by in-process examination in accordance with 344.7 of ANSI B31.3 plus examination by liquid penetrant or magnetic particle techniques after the final pass of the weld. If specified in the engineering design or specifically authorized by the inspector, examination by radiographic or ultrasonic techniques may be substituted for the examinations required by the previous sentence.

6-6.4 Nondestructive examination methods, limitations on defects, qualifications of the authorized inspector, and personnel performing the examination shall meet the requirements of 344 of ANSI B31.3.

Exception: Substitution of improcess examination for radiography or ultrasonics as permitted in 341.4.1 of ANSI B31.3 is prohibited.

6-6.5 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 reexamination is conducted.

6-6.6 Records and certifications pertaining to materials, components, and heat treatment as required by 341.4.1(c) and 341.4.3(d) of ANSI B31.3 shall be maintained for the life of the system.

6-7 Purging of Piping Systems.

6-7.1 Systems shall be purged of air or gas in a safe manner. Section 841.275 of ANSI B31.8, *Purging Pipelines and Mains*, may be used as a guide.

6-7.2 Blow-down and purge connections shall be provided to facilitate purging of all process and flammable gas piping.

6-8 Safety and Relief Valves.

6-8.1 Pressure relieving safety devices shall be so arranged that the possibility of damage to piping or appurtenance is reduced to a minimum. The means for adjusting relief valve set pressure shall be sealed.

6-8.2 A thermal expansion relief valve shall be installed as required to prevent overpressure in any section of a liquid or cold vapor pipeline that can be isolated by valves.

6-8.2.1 Thermal expansion relief valves shall be set to discharge above the maximum pressure normally expected in the line but less than the rated test pressure of the line it protects.

6-8.2.2 Discharge from such valves shall be directed as to minimize hazard to personnel and other equipment.

6-9 Corrosion Control.

6-9.1 Underground and submerged piping shall be protected and maintained in accordance with the principles of the National Association of Corrosion Engineers Standard RP-01-69, *Control of External Corrosion of Underground or Submerged Metallic Piping Systems.*

6-9.2 Austenitic stainless steels and aluminum alloys shall be protected to prevent unacceptable corrosion and pitting from corrosive atmospheric and industrial substances during storage, construction, fabrication, testing, and service. These substances include, but are not limited to, chlorides and compounds of sulphur or nitrogen. Tapes or other packaging materials that are corrosive to the pipe or piping components shall not be used. Where insulation materials can cause corrosion of aluminum or stainless steels, suitable inhibitors or waterproof barriers shall be utilized.

Chapter 7 Instrumentation and Electrical Services

7-1 Liquid Level Gaging.

7-1.1 LNG Containers.

7-1.1.1 LNG containers shall be equipped with two independent liquid level gaging devices. Density variations shall be considered in the selection of the gaging devices.These gages shall be replaceable without taking the tank out of operation.

7-1.1.2 The container shall be provided with a high-liquid-level alarm. The alarm shall be set so that the operator will have sufficient time to stop the flow without exceeding the maximum permissible filling height and shall be located sothat it is audible to personnel controlling the filling. A high-liquid-level flow cutoff device, if used, shall not be considered as a substitute for the alarm.

7-1.1.3 The LNG container shall be equipped with a high liquid level flow cutoff device, which shall be separate from all gages.

7-1.1.4 Containers with a capacity of 70,000 gal (265 m^3) or less, if attended during the filling operation, may be equipped with liquid trycocks in lieu of the high-liquid-level alarm, and manual flow cutoff is permitted.

7-1.2 Tanks for Refrigerants and/or Flammable Process Fluids.

7-1.2.1 Each storage tank shall be equipped with a liquid level gaging device. If it is possible to overfill the tank, as when the refrigerant or intermediate fluids system is a part of the liquefaction system, a high-liquid-level alarm shall be provided in accordance with 7-1.1.2.

7-1.2.2 Paragraph 7-1.1.3 shall apply to such installations.

7-2 Pressure Gage.

7-2.1 LNG Containers.

7-2.1.1 Each container shall be equipped with a pressure gage connected to the container at a point above the maximum intended liquid level.

7-2.2.2 Liquefaction Systems.

NOTE: It is recommended that pressure gages or taps be placed upstream and downstream of process equipment where trace contaminants in the feed stream may deposit as an aid to the scheduling of deriming operations.

7-3 Vacuum Gage.

7-3.1 Vacuum-Jacketed Equipment.

7-3.1.1 Vacuum-jacketed equipment shall be equipped with instruments or connections for checking the absolute pressure in the annular space.

7-4 Temperature Indicators.

7-4.1 LNG Containers.

7-4.1.1 Temperature monitoring devices shall be provided in field erected containers to assist in controlling temperatures when placing the container into service or as a method of checking and calibrating liquid level gages.

7-4.2 Vaporizers.

7-4.2.1 Vaporizers shall be provided with indicators to monitor inlet and outlet temperatures of LNG, vaporized gas, and heating medium fluids to assure effectiveness of the heat transfer surface.

7-4.3 Liquefaction Systems.

NOTE: It is recommended that temperature indicators be located upstream and downstream of process equipment where trace contaminants in the feed stream may deposit as an aid to the scheduling of deriming operations.

7-4.4 Heated Foundations of Cryogenic Containers and Equipment.

7-4.4.1 Temperature-monitoring systems shall be provided where foundations supporting cryogenic containers and equipment could be adversely affected by freezing or frost heaving of the ground.

7-5 Emergency Shutdown.

7-5.1 General Failsafe Requirement.

7-5.1.1 To the extent possible, instrumentation for liquefaction, storage, and vaporization facilities shall be designed so that, in the event power or instrument air failure occurs, the system will go into a failsafe condition that can be maintained until the operators can take appropriate action either to reactivate or to secure the system.

7-6 Electrical Equipment.

7-6.1 Electrical equipment and wiring shall be of the type specified by and shall be installed in accordance with NFPA 70, *National Electrical Code®*.

7-6.2 Fixed electrical equipment and wiring installed within the classified areas specified in Table 7-1 shall comply with Table 7-1 and shall be installed in accordance with NFPA 70, *National Electrical Code*, for hazardous locations.

7-6.3 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.

7-6.4 Each seal, barrier, or other means[1] used to comply with 7-6.3 shall be designed to prevent the passage of flammable fluids through the conduit, stranded conductors, and cables.

7-6.5 A primary seal shall be provided between the flammable fluid system and the electrical conduit wiring system. If the failure of the primary seal would allow the passage of flammable fluids to another portion of the conduit or wiring system, an additional approved seal, barrier, or other means[1] shall be provided to prevent the passage of the flammable fluid beyond the additional device or means if the primary seal fails.

7-6.6 Each primary seal shall be designed to withstand the service conditions to which it may be exposed. Each additional seal or barrier and interconnecting enclosure shall 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.

7-6.7 Unless specifically designed and approved for the purpose, the seals specified in 7-6.3, 7-6.4, and 7-6.5 are not intended to replace the conduit seals required in 501-5(a)(b)(c) and (d) of NFPA 70, *National Electrical Code*.

7-6.8 Where primary seals are installed, drains, vents, or other devices shall be provided for monitoring purposes to detect flammable fluids and leakage.

[1]Examples of such "other means" may include a physical interruption of the conduit run and of the stranded conductor(s) through the use of an adequately vented junction box containing terminal strip or busbar connections; an exposed section of MI cable using suitable fittings; or an exposed section of single conductor(s) which is incapable of transmitting gases or vapors. [see 501-5(a)(b)(c) and (d) of NFPA 70, *National Electrical Code*.]

7-6.9 The venting of a conduit system shall be done in a manner that will minimize the possiblity of damage to personnel and equipment considering the properties of the liquid or gas and the potential for ignition.

7-7 Electrical Grounding and Bonding.

7-7.1 General.

7-7.1.1 Electrical grounding and bonding shall be provided as recommended by Section 5-4 and 6-1.3 of NFPA 77, *Static Electricity*, and as required by NFPA 70, *National Electrical Code*.

7-7.2 Bonding.

7-7.2.1 Static protection is not required when tank cars, tank vehicles, or marine equipment are loaded or unloaded by conductive or nonconductive hose, flexible metallic tubing, or pipe connections through or from tight (top or bottom) outlets where both halves of metallic couplings are in contact.

7-7.3 Stray or Impressed Currents.

7-7.3.1 If stray currents may 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 in accordance with API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning and Stray Currents*.

7-7.4 Lightening Protection.

7-7.4.1 Although metallic storage containers and tanks do not require lightning protection, ground rods shall be provided for tanks supported on nonconductive foundations for personnel and foundation protection. (*See NFPA 78, Lightning Protection Code, and API RP 2003, Protection Against Ignitions Arising Out of Static, Lightning and Stray Currents, for additional information on lightning protection.*)

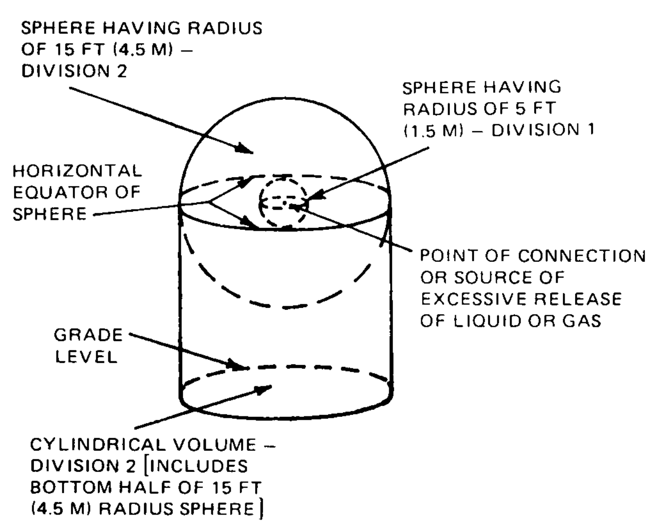

Figure 7-1 (See Table 7-1)

Table 7-1

Part	Location	Equipment Shall Be Suitable for NEC (NFPA 70) Class I Group D, Division[1]	Extent of Classified Area[2]
A	**LNG Storage Container Area**		
	Indoors	1	Entire room.
	Outdoor, aboveground containers. (Other than small containers)[5]	1	Open area between a high-type dike and container wall where dike wall height exceeds distance between dike and container walls. (*See Figure 7-3.*)
		2	Within 15 ft (4.5 m) in all directions from container walls and roof, plus area inside a low-type diked or impounding area up to the height of the dike impoundment wall. (*See Figure 7-2.*)
	Outdoor belowground containers.	1	Within any open space between container walls and surrounding grade or dike. (*See Figure 7-4.*)
		2	Within 15 ft (4.5 m) in all directions from roof and sides. (*See Figure 7-4.*)
B	**Nonfired LNG Process Areas Containing Pumps, Compressors, Heat Exchangers, Pipelines, Connections, Small Containers, etc.**		
	Indoors with adequate ventilation[3]	2	Entire room and any adjacent room not separated by a gastight partition, and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver.
	Outdoors in open air at or above grade.	2	Within 15 ft (4.5 m) in all directions from this equipment, and within the cylindrical volume between the horizontal equator of the sphere and grade. (*See Figure 7-1.*)
C	**Pits, Trenches or Sumps Located in or Adjacent to Division 1 or 2 Areas.**	1	Entire pit, trench or sump.
D	**Discharge from Relief Valves**	1	Within direct path of relief valve discharge.
E	**Operational Bleeds, Drips, Vents or Drains**		
	Indoors with adequate ventilation[3]	1	Within 5 ft (1.5 m) in all directions from point of discharge.
		2	Beyond 5 ft (1.5 m) and entire room and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver.
	Outdoors in open air at or above grade	1	Within 5 ft (1.5 m) in all directions from point of discharge.
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from point of discharge.
F	**Tank Car, Tank Vehicle, and Container Loading and Unloading[4]**		
	Indoors with adequate ventilation.[3]	1	Within 5 ft (1.5 m) in all directions from connections regularly made or disconnected for product transfer.
		2	Beyond 5 ft (1.5 m) and entire room and 15 ft (4.5 m) beyond any wall or roof ventilation discharge vent or louver.

(cont.)

Table 7-1 (cont.)

Part	Location	Equipment Shall Be Suitable for NEC (NFPA 70) Class I Group D, Division[1]	Extent of Classified Area[2]
	Outdoors in open air at or above grade.	1	Within 5 ft (1.5 m) in all directions from connections regularly made or disconnected for product transfer.
		2	Beyond 5 ft (1.5 m) but within 15 ft (4.5 m) in all directions from a point where connections are regularly made or disconnected, and within the cylindrical volume between the horizontal equator of the sphere and grade. (*See Figure 7-1.*)
G	**Electrical Seals and Vents Specified in 7-6.3, 7-6.4, and 7-6.5**	2	Within 15 ft (4.5 m) in all directions from the equipment and within the cylindrical volume between the horizontal equator of the sphere and grade.

[1] See Article 500—"Hazardous (Classified) Locations" in NFPA 70 (ANSI) for definitions of Classes, Groups, and Divisions. Most of the flammable vapors and gases found within the facilities covered by this standard are classified as Group D. Ethylene is Group C. Much available electrical equipment for hazardous locations is suitable for both Groups.
[2] The classified area shall not extend beyond an unpierced wall, roof, or solid vaportight partition.
[3] Ventilation is considered adequate when provided in accordance with the provisions of this standard.
[4] When classifying extent of hazardous area, consideration shall be given to possible variations in the spotting of tank cars and tank vehicles at the unloading points and the effect these variations of actual spotting point may have on the point of connection.
[5] Small containers are those that are portable and of less than 200 gal (760 L) capacity.

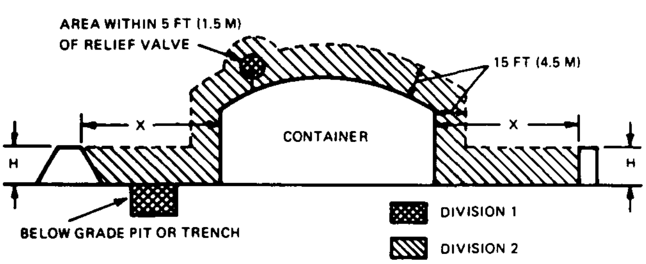

Figure 7-2 Dike height less than distance from container to dike (H less than X).

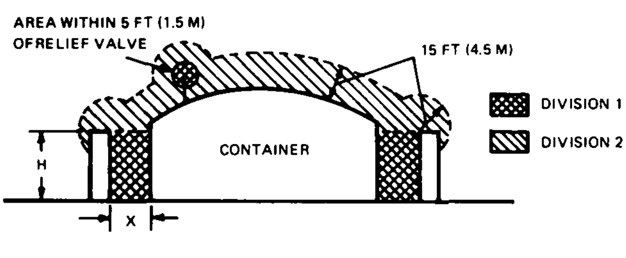

Figure 7-3 Dike height less than distance from container to dike (H greater than X).

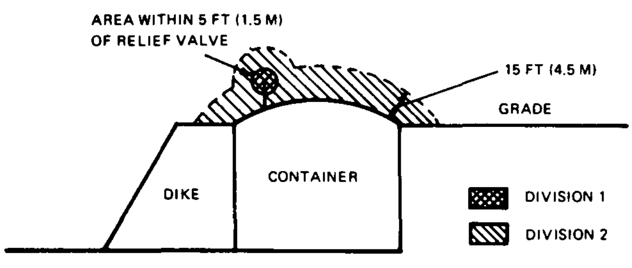

Figure 7-4 Container with liquid level below grade or top of dike.

Chapter 8 Transfer of LNG and Refrigerants

8-1 General.

8-1.1 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.

8-1.2 Transfer facilities shall comply with the appropriate provisions elsewhere in this standard, such as those applying to siting, piping systems, and instrumentation, as well as the specific provisions of this chapter.

8-1.3 When making bulk transfers into stationary storage containers, the LNG being transferred shall be

(a) compatible in composition or temperature and density with that already in the container, or

(b) when the composition or temperature and density are not compatible, means shall be taken to prevent stratification, which might result in "roll over" and an excessive rate of vapor evolution. Stratification may be prevented by means such as: introducing the denser liquid above the surface of the stored liquid, introducing the lighter LNG into the bottom of the container, mechanical agitation, or introducing the LNG into the container through an inlet nozzle designed to promote mixing. If a mixing nozzle or agitation system is provided, it shall be designed so as to have sufficient energy to accomplish its purpose.

8-2 Piping System.

8-2.1 Isolation valves shall be installed so that each transfer system can be isolated at its extremities. When power-operated isolation valves are installed, an analysis shall be made to determine that the closure time will not produce a hydraulic shock capable of causing line or equipment failure. If excessive stresses are indicated by the analysis, increase of valve closure time or other methods shall be taken to reduce the stresses to a safe level.

8-2.2 A piping system used for periodic trnsfer of a cold fluid shall be provided with suitable means for precooling before use.

8-2.3 Check valves shall be provided as required 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.

8-3 Pump and Compressor Control.

8-3.1 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 emergency. Remotely located pumps and compressors used for loading or unloading tank cars, tank vehicles, or marine vessels shall be provided with controls at the loading or unloading area and at the pump or compressor site for stopping. Controls located aboard a marine vessel shall be considered as in accordance with this provision.

8-3.2 Signal lights shall be provided at the loading or unloading area to indicate when a remotely located pump or compressor used for loading or unloading is idle or in operation.

8-4 Marine Shipping and Receiving.

8-4.1 Design, construction, and operation of piers, docks, and wharves shall comply with requirements of the authorities having jurisdiction. NFPA 30, *Flammable and Combustible Liquids Code*, may be used for guidance as appropriate.

8-4.2 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. Ship bunkering may be done provided that bunkering is from a pipeline rather than a barge.

8-4.3 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. Suitable warning signs or barricades shall be used to indicate when transfer operations are in progress.

8-4.4 Pipelines shall be located on the dock or pier so that they are not exposed to damage from vehicular traffic or other possible cause of physical damage. 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 in accordance with federal regulations.

8-4.5 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. Liquid isolation valves, regardless of size, and vapor valves 8 in. and larger in size shall be equipped with powered operators in addition to means for manual operation. Power-operated valves shall be capable of being closed from a remote control station located at least 50 ft (15 m) from the manifold area as well as locally. Unless the valve will automatically fail 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 10 minutes duration. Valves shall be located at the point of hose or arm connection to the manifold. Bleeds or vents shall discharge to a safe area.

8-4.6 In addition to the isolation valves at the manifold, each vapor return and liquid transfer line shall be provided with a readily accessible isolation valve located on shore near the approach to the pier or dock. Where more than one line is involved, the valves shall be grouped in one location. Valves shall be identified as to their service. Valves 8 in. and larger in size shall be equipped with powered operators. Means for manual operation shall be provided.

8-4.7 Pipelines used for liquid unloading only shall be provided with a check valve located at the manifold adjacent to the manifold isolation valve.

8-4.8 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.

8-4.9 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 proper operating condition. Following this inspection, they shall meet and determine the transfer procedure, verify that adequate ship-to-shore communications exist, and review emergency procedures.

8-5 Tank Vehicle and Tank Car Loading and Unloading Facilities.

8-5.1 Transfer shall be made only into tank cars approved for the specific service.

8-5.1.1 Tank vehicles and tank cars under the jurisdiction of the U.S. Department of Transportation (DOT), including those in interstate commerce, shall comply with regulations and specifications of that federal agency.

8-5.1.2 Tank vehicles not under the jurisdiction of the DOT shall comply with:

(a) LNG Tank Vehicles — CGA-341, *Standard for Insulated Cargo Tank Specification for Cryogenic Liquids*

(b) LP-Gas Tank Vehicles — NFPA 58, *Storage and Handling of Liquefied Petroleum Gases*

(c) Flammable Liquid Tank Vehicles — NFPA 385, *Tank Vehicles for Flammable and Combustible Liquids.*

8-5.2 A rack structure, if provided, shall be constructed of noncombustible material, such as steel or concrete.

8-5.3 A tank vehicle loading and unloading area shall be of sufficient size to accommodate the vehicles without excessive movement or turning.

8-5.4 Transfer piping, pumps, and compressors shall be located or protected by suitable barriers so that they are safe from damage by rail or vehicle movements.

8-5.5 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 of liquid, and depressured before disconnecting. Bleeds or vents shall discharge to a safe area.

8-5.6 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. These valves shall be readily accessible for emergency use. A single valve may be installed in a common line to multiple loading or unloading areas.

8-5.6.1 In installations 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 remotely operated from a point between 25 and 100 ft (7.6 and 30 m) from the area is acceptable.

8-5.7 Pipelines used for liquid unloading only shall be provided with a check valve at the manifold adjacent to the manifold isolation valve.

8-6 Pipeline Shipping and Receiving.

8-6.1 Isolation valves shall be provided at all points where transfer systems connect into pipeline systems.

8-6.2 Provisions shall be made to assure that transfers into pipeline delivery systems will not exceed the pressure or temperature limitations of the pipeline system.

8-7 Loading or Unloading Operations.

8-7.1 General.

8-7.1.1 At least one qualified person shall be in constant attendance while loading or unloading is in progress.

8-7.1.2 Written procedures shall be available to cover all transfer operations and shall cover emergency as well as normal operating procedures. They shall be kept up-to-date and available to all personnel engaged in transfer operations.

8-7.1.3 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.

8-7.1.4 Loading and unloading areas shall be posted with "No Smoking" signs.

8-7.1.5 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.

8-7.1.6 Prior to transfer, gage readings shall be obtained or inventory established to ensure that the receiving vessel will not be overfilled. Levels shall be checked during transfer operations.

8-7.1.7 The transfer system shall be checked prior to use to see that valves are properly lined up. 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. Pressure and temperature conditions shall be observed during the transfer operation.

8-7.1.8 Bleed or vent connections shall be provided so that loading arms and hoses can be drained and depressurized prior to disconnecting. These bleeds or vents shall discharge to a safe area.

8-7.1.9 Gas or liquid is permitted to be vented to the atmosphere to assist in transferring the contents of one container to another if vented to a safe location.

8-7.1.10 No significant repair shall be done on the transfer system while transfer is taking place.

8-7.2 Tank Car or Tank Vehicle.

8-7.2.1 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.

8-7.2.2 Prior to connecting a tank car, the car shall be chocked and brakes set, the derailer or switch properly positioned, and warning signs or lights placed as required. They shall not be removed or reset until transfer is completed and the car disconnected.

8-7.2.3 Unless required for transfer operations, truck vehicle engine shall be shut off. Brakes shall be set and wheels chocked prior to connecting for unloading or loading. The engine shall not be started until the truck vehicle has been disconnected and any released vapors have dissipated.

8-7.2.4 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. If a tank car or tank vehicle in exclusive LNG service does not contain a positive pressure, it shall be tested for oxygen content. If the oxygen content in either case exceeds 2 percent by volume, the container shall not be loaded until suitably purged.

8-7.2.5 A tank vehicle shall be positioned prior to loading or unloading so that it can exit the area without backing when the transfer operation is complete.

8-7.2.6 When required by NFPA 77, *Static Electricity*, tank cars and tank vehicles that are top loaded through an open dome shall be electrically bonded to the fill piping or grounded prior to opening the dome.

8-8 Hoses and Arms.

8-8.1 Hoses or arms used for transfer shall be suitable for the temperature and pressure conditions encountered. Hoses shall be approved for the service and shall be designed for a bursting pressure of not less than five times the working pressure.

8-8.2 Flexible metallic hose or pipe and swivel joints shall be used where operating temperatures will be below -60°F (-51°C).

8-8.3 Loading arms used for marine loading or unloading shall be provided with alarms to indicate when the arms are approaching the limits of their extension envelopes.

8-8.4 Provisions shall be made for adequately supporting the loading hose or arm. Counterweights shall take into consideration any ice formation on uninsulated hoses or arms.

8-8.5 Couplings used for connection of a hose or arm shall be suitable for operating conditions and shall be satisfactory for frequent coupling and uncoupling conditions.

8-8.6 Hoses shall be tested at least annually to the maximum pump pressure or relief valve setting and shall be visually inspected before each use for damage or defects.

8-9 Communications and Lighting.

8-9.1 Communications shall be provided at a loading and unloading location so that the operator can be in contact with other remotely located personnel who are associated with the loading or unloading operation. Communication can be by means of telephone, public address systems, radio, or signal lights.

8-9.2 All transfer areas shall be illuminated in accordance with API RP 540, *Recommended Practice for Electrical Installations in Petroleum Processing Plants*.

Chapter 9 Fire Protection, Safety, and Security

9-1 General.

9-1.1 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. These provisions augment the leak and spill control provisions provided for in other chapters. This chapter also includes basic plant security provisions.

9-1.2 Fire protection shall be provided for all LNG facilities. The extent of such protection shall be determined by an evaluation based upon sound fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property. The evaluation shall determine, as a minimum:

(a) 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

(b) The type, quantity, and location of equipment necessary for the detection and control of potential nonprocess and electrical fires

(c) The methods necessary for protection of the equipment and structures from the effects of fire exposure

(d) Fire protection water systems (*see Section 9-5*)

(e) Fire extinguishing and other fire control equipment (*see Section 9-6*)

(f) The equipment and processes to be incorporated within the Emergency Shutdown (ESD) system (*see Section 9-3*), including analysis of subsystems, if any, and the need for depressurizing specific vessels or equipment during a fire emergency

(g) The type and location of sensors necessary to initiate automatic operation of the Emergency Shutdown (ESD) system or its subsystems

(h) The availability and duties of individual plant personnel and the availability of external response personnel during an emergency

(i) The protective equipment and special training needed by the individual plant personnel for their respective emergency duties.

9-1.3 The wide range in size, design, and location of LNG facilities covered by this standard precludes the inclusion of detailed fire protection provisions completely applicable to all facilities.

9-1.4 A detailed emergency procedure manual shall be prepared to cover the potential emergency conditions that may develop whether or not a fire has occurred. Such procedures shall include but not necessarily be limited to the following:

(a) 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

(b) use of fire protection facilities

(c) notification of public authorities

(d) first aid, and

(e) duties of personnel.

9-1.4.1 The emergency procedure manual shall be kept readily available in the operating control room, and it shall be updated as required by changes in equipment or procedures.

9-1.4.2 All personnel shall be trained in their respective duties contained in the emergency manual. Those personnel responsible for the use of fire protection or other plant emergency equipment shall be trained in the use of that equipment. Refresher training shall be conducted at least on an annual basis.

NOTE: For information on fire brigades see NFPA 600, *Recommendations for Organization, Training and Equipment of Private Fire Brigades*.

9-1.5 The planning of effective fire control measures shall be coordinated with the authority having jurisdiction and local emergency handling agencies, such as fire and police departments, who are expected to respond to such emergencies.

9-1.6 Normally, gas fires (including LNG) should not be extinguished until the fuel source has been shut off.

9-2 Ignition Source Control.

9-2.1 Smoking and nonprocess ignition sources within the protective enclosure shall be prohibited, except in accordance with 9-2.1.1 through 9-2.1.3.

9-2.1.1 Smoking shall be permitted only in designated and properly signposted areas.

9-2.1.2 Welding, cutting, and similar operations shall be conducted only at times and in places specifically authorized, and in accordance with the provisions of NFPA 51B, *Fire Prevention in Use of Cutting and Welding Processes*.

9-2.1.3 Vehicles and other mobile equipment that constitute potential ignition sources shall be prohibited within impounding areas or within 50 ft (15 m) of containers or equipment containing LNG, flammable liquids, or flammable refrigerants except when specifically authorized and under constant supervision or when at loading or unloading facilities specifically for the purpose.

9-3 Emergency Shutdown Systems.

9-3.1 Each LNG facility shall incorporate an Emergency Shutdown (ESD) system or systems, which, when operated, will isolate or shut off a source of LNG, flammable liquids, flammable refrigerant, or flammable gases, and shut downequipment whose continued operation could add to or continue an emergency. Any equipment, such as valves or control systems, that is specified in another chapter may be used to satisfy the requirements of an Emergency Shutdown (ESD) system except where otherwise indicated, e.g., 5-3.3.

9-3.1.1 If equipment shutdown will introduce an additional hazard or result in substantial mechanical damage to equipment the shutdown of such equipment or its auxiliaries may be omitted from the Emergency Shutdown (ESD) system provided that the effects of continued release of flammable or combustible fluids are controlled.

9-3.2 Vessels containing liquids that are subject to metal overheating and catastrophic failure from fire exposure and not otherwise protected shall be depressurized by the Emergency Shutdown (ESD) system.

9-3.3 The Emergency Shutdown (ESD) system, or systems, shall be of failsafe design or otherwise installed, located, or protected so as to minimize the possibility that it may become inoperative in the event of an emergency or failure at the normal control system. Emergency Shutdown (ESD) systems that are not of failsafe design shall have all components that are located within 50 ft (15 m) of the equipment to be controlled either:

(a) Installed or located where they will not be exposed to a fire, or

(b) Be protected against failure due to a fire exposure of at least 10 minutes duration.

9-3.4 Initiation of the Emergency Shutdown (ESD) system, or systems, shall either be manual, automatic, or both manual and automatic, depending upon the results of the evaluation performed in accordance with 9-1.2. Manual actuators shall be located in an area accessible in an emergency, at least 50 ft (15 m) from the equipment it serves, and shall be distinctly and conspicuously marked with their designated function.

9-4 Fire and Leak Control.

9-4.1 Those areas, including enclosed buildings, that have a potential for flammable gas concentrations, LNG or flammable refrigerant spills, and fire shall be monitored as appropriate.

9-4.2 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 continuously manned. Flammable gas detection systems shall sound this alarm at not more than 25 percent of the lower flammable limit of the gas or vapor being monitored.

9-4.3 Fire detectors shall sound an alarm at the plant site and at a constantly attended location if the plant site is not continually manned. In addition, if so determined by an evaluation in accordance with 9-1.2, fire detectors may activate appropriate portions of the Emergency Shutdown (ESD) system.

9-4.4 The detection systems determined in 9-1.2 shall be designed, installed, and maintained in accordance with the following NFPA standards, as applicable:

(a) NFPA 72A, *Local Protective Signaling Systems*

(b) NFPA 72B, *Auxiliary Protective Signaling Systems*

(c) NFPA 72C, *Remote Station Protective Signaling Systems*

(d) NFPA 72D, *Proprietary Protective Signaling Systems*

(e) NFPA 72E, *Automatic Fire Detectors*

(f) NFPA 1221, *Public Fire Service Communications*.

9-5 Fire Protection Water Systems.

9-5.1 A water supply and a system for distributing and applying water shall be provided for protection of exposures; cooling containers, equipment, and piping; and controlling unignited leaks and spills unless an evaluation in accordance with 9-1.2 indicates the use of water is unnecessary or impractical.

9-5.2 The design of fire water supply and distribution systems, if provided, shall provide for the simultaneous supply of those 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/s) for hand hose streams for a period of not less than 2 hours.

9-5.3 Fire protection water systems shall be designed, installed and maintained in accordance with the following NFPA standards, as applicable:

(a) NFPA 13, *Installation of Sprinkler Systems*

(b) NFPA 13A, *Care and Maintenance of Sprinkler Systems*

(c) NFPA 14, *Standpipe and Hose Systems*

(d) NFPA 15, *Water Spray Fixed Systems*

(e) NFPA 20, *Centrifugal Fire Pumps*

(f) NFPA 22, *Water Tanks for Private Fire Protection*

(g) NFPA 24, *Private Fire Service Mains and Their Appurtenances*

(h) NFPA 26, *Supervision of Valves Controlling Water Supplies*

(i) NFPA 1963, *Screw Threads and Gaskets for Fire Hose Connections*

(j) NFPA 1961, *Fire Hose*

(k) NFPA 1962, *Care, Use, and Maintenance of Fire Hose.*

9-6 Fire Extinguishing and Other Fire Control Equipment.

9-6.1 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 9-1.2, within an LNG facility and on tank vehicles. These extinguishers shall be provided and maintained in accordance with NFPA 10, *Portable Fire Extinguishers.*

9-6.2 Fixed fire extinguishing and other fire control systems may be appropriate for the protection of specific hazards as determined in accordance with 9-1.2. If provided, such systems shall be designed, installed, and maintained in accordance with the following NFPA standards, as applicable:

(a) NFPA 11, *Low Expansion Foam and Combined Agent Systems*

(b) NFPA 11A, *Medium and High Expansion Foam Systems*

(c) NFPA 12, *Carbon Dioxide Extinguishing Systems*

(d) NFPA 12A, *Halon 1301 Fire Extinguishing Systems*

(e) NFPA 12B, *Halon 1211 Fire Extinguishing Systems*

(f) NFPA 16, *Deluge Foam-Water Sprinkler and Foam-Water Spray Systems*

(g) NFPA 17, *Dry Chemical Extinguishing Systems.*

9-6.3 If provided, automotive and trailer-mounted fire apparatus shall not be used for any other purpose. Fire trucks shall conform to applicable portions of NFPA 1901, *Automotive Fire Apparatus.*

9-6.4 Plant assigned automotive vehicles shall be provided with a minimum of one portable dry chemical extinguisher having a capacity of not less than 20 lb (9 kg).

9-7 Maintenance of Fire Protection Equipment.

9-7.1 Facility operators shall prepare and implement a maintenance program for all plant fire protection equipment.

9-8 Security.

9-8.1 The facility operator shall provide a security system with controlled access that shall be designed to minimize entry by unauthorized persons.

9-8.2 At LNG facilities there shall be a protective enclosure including a peripheral fence, building wall, or natural barrier enclosing major facility components, such as:

(a) LNG storage containers

(b) Flammable refrigerant storage tanks

(c) Flammable liquid storage tanks

(d) Other hazardous materials storage areas

(e) Outdoor process equipment areas

(f) Buildings housing process or control equipment

(g) Onshore loading and unloading facilities.

9-8.3 The provisions of 9-8.2 may be met by either one continuous enclosure or several independent enclosures. When the enclosed area exceeds 1250 sq ft (116 m^2), at least two exit gates or doors shall be provided for rapid escape of personnel in the event of an emergency.

9-8.4 LNG facilities shall be illuminated as necessary in the vicinity of protective enclosures and in other areas to promote security of the facility.

9-9 Personnel Safety.

9-9.1 Personnel shall be advised of the serious danger from frostbite, that can result upon contact with LNG or cold refrigerants.

9-9.1.1 Suitable protective clothing and equipment shall be available.

9-9.2 Those employees who will be involved in emergency activities, as determined in accordance with 9-1.2, shall be equipped with the necessary clothing and equipment. Protective clothing shall comply with NFPA 1971, *Protective Clothing for Structural Fire Fighting*, and have an impermeable outer shell. Those employees requiring such protective clothing shall also be equipped with helmets, face shields, gloves, and boots suitable for the intended exposure.

9-9.3 Self-contained breathing apparatus shall be provided for those employees who may be required to enter an atmosphere that could be injurious to health during an emergency. Such apparatus shall comply with NFPA 1981, *Open-Circuit Self-Contained Breathing Apparatus for Fire Fighters*, and be maintained in accordance with the manufacturer's instructions.

9-9.4 Because natural gas, LNG, and hydrocarbon refrigerants within the process equipment are usually not odorized and the sense of smell cannot be relied upon to detect their presence, a portable flammable gas indicator shall be readily available.

9-10 Other Operations.

NOTE: If a liquefaction plant is designed to operate unattended, it is recommended that alarm circuits be provided which will transmit an alarm to the nearest manned company facility indicating abnormal pressure, temperature, or other symptons of trouble.

9-10.1 Where gas must be released intermittently or in an emergency, a discharge directed upward at high velocity will safely dissipate the gas. Separate release points may be preferable to collecting the discharge from several relief valves in a common header. An ignited flare is permitted in LNG facilities if local conditions warrant.

9-10.2 Purging procedures shall be developed that will minimize the presence of a combustible mixture in plant piping or equipment when a system is being placed into or taken out of operation.

9-10.3 Manual emergency depressuring means shall be provided where practicable. Portions of the plant that can be isolated from storage tanks or other sources of supply can be depressured by venting to the atmosphere through upward pointing vent stacks. Lever operated relief valves can often be used for this purpose.

9-10.4 Taking an LNG container out of service is not to be regarded as a normal operation and should not be attempted on any routine basis. All such activities require the preparation of detailed procedures.

Chapter 10 Referenced Publications

10-1 The following documents or portions thereof are referenced within this standard and shall be considered part of the requirements of this document. The edition indicated for each reference is the current edition as of the date of the NFPA issuance of this document.

10-1.1 NFPA Publications. National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101.

NFPA 10-1988, *Standard for Portable Fire Extinguishers*

NFPA 11-1988, *Standard for Low Expansion Foam and Combined Agent Systems*

NFPA 11A-1988, *Standard for Medium and High Expansion Foam Systems*

NFPA 12-1989, *Standard on Carbon Dioxide Extinguishing Systems*

NFPA 12A-1989, *Standard on Halon 1301 Fire Extinguishing Systems*

NFPA 12B-1985, *Standard on Halon 1211 Extinguishing Systems*

NFPA 13-1989, *Standard for the Installation of Sprinkler Systems*

NFPA 13A-1987, *Recommended Practice for the Care and Maintenance of Sprinkler Systems*

NFPA 14-1990, *Standard for the Installation of Standpipe and Hose Systems*

NFPA 15-1985, *Standard for Water Spray Fixed Systems for Fire Protection*

NFPA 16-1986, *Standard for the Installation of Foam-Water Sprinkler Systems and Foam-Water Spray Systems*

NFPA 17-1990, *Standard for Dry Chemical Extinguishing Systems*

NFPA 20-1990, *Standard for the Installation of Centrifugal Fire Pumps*

NFPA 22-1987, *Standard for Water Tanks for Private Fire Protection*

NFPA 24-1987, *Standard for Installation of Private Fire Service Mains and Their Appurtenances.*

NFPA 26-1988, *Recommended Practices for the Supervision of Valves Controlling Water Supplies for Fire Protection*

NFPA 30-1987, *Flammable and Combustible Liquids Code*

NFPA 37-1990, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*

NFPA 51B-1989, *Standard for Fire Prevention in Use of Cutting and Welding Processes*

NFPA 58-1989, *Standard for the Storage and Handling of Liquefied Petroleum Gases*

NFPA 59-1989, *Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants*

NFPA 70-1990, *National Electrical Code*

NFPA 72A-1987, *Standard for the Installation, Maintenance and Use of Local Protective Signaling Systems for Guard's Tour, Fire Alarm and Supervisory Service*

NFPA 72B-1986, *Standard for the Installation, Maintenance and Use of Auxiliary Protective Signaling Systems*

NFPA 72C-1986, *Standard for the Installation, Maintenance and Use of Remote Station Protective Signaling Systems*

NFPA 72D-1986, *Standard for the Installation, Maintenance and Use of Proprietary Protective Signaling Systems for Guard, Fire Alarm and Supervisory Service*

NFPA 72E-1987, *Standard on Automatic Fire Detectors*

NFPA 77-1988, *Recommended Practice on Static Electricity*

NFPA *101*-1988, *Code for Safety to Life from Fire in Buildings and Structures*

NFPA 255-1984, *Method of Test of Surface Burning Characteristics of Building Materials*

NFPA 385-1990, *Recommended Regulatory Standard for Tank Vehicles for Flammable and Combustible Liquids*

NFPA 600-1986, *Recommendations for Organization, Training and Equipment of Private Fire Brigades*

NFPA 1221-1988, *Standard for the Installation, Maintenance and Use of Public Fire Service Communications*

NFPA 1901-1985, *Standard for Automotive Fire Apparatus*

NFPA 1961-1987, *Standard for Fire Hose*

NFPA 1962-1988, *Standard for the Care, Use, and Maintenance of Fire Hose Including Connections and Nozzles*

NFPA 1963-1985, *Standard for Screw Threads and Gaskets for Fire Hose Connections*

NFPA 1971-1986, *Standard on Protective Clothing for Structural Fire Fighting*

NFPA 1981-1987, *Standard on Self-Contained Breathing Apparatus for Fire Fighters*