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G.J. Konzek
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June 1982

Prepared for the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

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Pacific Northwest Laboratory
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FOREWORD

This report is one of a series prepared by Pacific Northwest Laboratory (PNL) to communicate results of the Liquefied Gaseous Fuels (LGF) Safety Studies Project, being performed for the U.S. Department of Energy, Office of Environmental Protection, Safety and Emergency Preparedness (DOE/EP). The DOE/EP Office of Operational Safety, Environmental and Safety Engineering Division (ESED), is conducting the DOE Liquefied Gaseous Fuels Safety and Environmental Control Assessment Program. The LGF Safety Studies project contributes research, technical surveillance and program development information in support of the ESED Assessment Program. This study of LNG fire and vapor control system technologies benefited from the technical direction and guidance provided by Dr. Henry F. Walter and Dr. John M. Cece of ESED.

Completed effort in other tasks of the PNL project are reported in:

1. Assessment of Research and Development (R&D) Needs in LPG safety and Environmental Control (PNL-3991)
2. Assessment of Research and Development (R&D) Needs in Ammonia Safety and Environmental Control (PNL-4006)
3. An Overview Study of LNG Release Prevention and Control Systems (PNL-4014)
4. Applications of Human Factors Engineering to LNG Release Prevention and Control (PNL-4090)
5. Analysis of LNG Import Terminal Release Prevention Systems (PNL-4152)
6. Analysis of LNG Peakshaving Facility Release Prevention Systems (PNL-4153)

Work in progress includes a detailed analysis of LNG storage tank operations.

ACKNOWLEDGMENTS

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1.0 SUMMARY

This report provides a review of fire and vapor control practices used in the liquefied natural gas (LNG) industry. Specific objectives of this effort were to summarize the state-of-the-art of LNG fire and vapor control; define representative LNG facilities and their associated fire and vapor control systems; and develop an approach for a quantitative effectiveness evaluation of LNG fire and vapor control systems.

In this report a brief summary of LNG physical properties is given. This is followed by a discussion of basic fire and vapor control design philosophy and detailed reviews of fire and vapor control practices. The operating characteristics and typical applications and application limitations of leak detectors, fire detectors, dikes, coatings, closed circuit television, communication systems, dry chemicals, water, high expansion foam, carbon dioxide and halogenated hydrocarbons are described.

Summary descriptions of a representative LNG peakshaving facility and import terminal are included in this report together with typical fire and vapor control systems and their locations in these types of facilities. These representative descriptions illustrate how fire and vapor control practices are generally incorporated into an actual facility design and also provide a base case for more detailed generic evaluations of fire and vapor control systems.

This state-of-the-art review identifies large differences in the application of fire and vapor control systems throughout the LNG industry. A systematic effectiveness evaluation could be useful in selecting alternative fire and vapor control systems when designing new LNG plants or upgrading older facilities. A general evaluation procedure is outlined for this purpose. This procedure is based on reliability and capability analyses and entails a phased approach which proceeds through increasing levels of detail according to need. This procedure is proposed as a tool for evaluating the effectiveness of future LNG fire and vapor control systems.

2.0 INTRODUCTION

LNG facilities are designed with features to detect, limit, and/or control the hazards of potential LNG releases. These features include systems for the detection of fire and vapor along with active and passive control systems.

All LNG facilities must be designed to meet a minimum level of safety. Related government standards are designed to provide this level of safety through a combination of engineering features and site-selection procedures. In reality, the determination of what constitutes a minimum level of safety at an LNG facility is based on the combined experience of a committee of fire protection experts acting in accordance with their interpretation of code requirements, engineering judgment, and client preference. These experts, working in conjunction with the facility designer, consider potential accidents, postulate their consequences, and recommend measures to minimize their potential. The basic criterion for all fire protection and fire and vapor control systems is that they shall be designed in accordance with good fire protection engineering principles to minimize the occurrence and consequences of fires. It is recognized that, due to location, size, specific design requirements, and cost considerations, each LNG facility is afforded considerable latitude of design in meeting the defined level of safety.

Several succinct but dated summaries of the hazard control systems and techniques used by the LNG industry for vapor dispersion and fire control are available in the open literature (Drake and Wesson 1976, Wesson 1975). This information is used by many different segments of society for assessing the safety of existing LNG facilities and by the LNG industry itself for assuring that reliable fire and vapor control (F&VC) design parameters are met in the construction of safe, new facilities. However, a gap appears to exist between industry and government fire protection research findings and usable field application.

This study assesses state-of-the-art and industrial practices relating to LNG fire and vapor control technologies. Section 3.0 provides a brief summary of LNG physical properties pertinent to F&VC systems. A basic fire and vapor control design philosophy is discussed in Section 4.0. Section 5.0 describes typical applications, controlling parameters, limitations, and operational characteristics of commercially available F&VC systems. A representative LNG peak-shaving plant and a representative LNG import facility are used to describe the F&VC systems and are outlined in Section 6.0. Section 7.0 gives a general procedure for fire and vapor control system effectiveness evaluations. The conclusions and recommendations of this report are discussed in Section 8.0.

3.0 PROPERTIES OF LNG

A basic understanding of the properties of LNG is important in recognizing the strengths and weaknesses of fire and vapor detection and control systems. This section discusses the properties of LNG including the potential hazards of transporting it and its various behavior patterns.

Liquefied natural gas is odorless and colorless. It looks much like water. Except for its extremely cold temperature, which requires special handling techniques and materials, the liquid is relatively safe. In bulk form it will not burn or explode. Momentary contact on the skin is harmless, although extended contact will cause severe freeze burns.

Some unique properties of LNG are as follows (Library of Congress 1977, Katz et al. 1975):

- It has an extremely low temperature of -259°F.
- Since it weighs about 28 lb/ft^3, slightly less than half the weight of water, it floats.
- At normal ambient temperatures, it evaporates very rapidly and expands to about 600 times its liquid volume.
- In the vapor state, and when still very cold, it is heavier than air and, when spilled, it hugs the earth's surface for a period of time until it substantially dissipates.
- When the vapor warms up, reaching temperatures of about -100°F, it becomes lighter than air and rises and dissipates.
- In the vapor state, it is not poisonous, but could cause asphixiation due to the absence of oxygen.
- LNG spills vaporize completely; thus they do not present a pollution problem similar to that found following a spill of crude oil or gasoline.
- In the vapor state, concentrations of 5 to 15% natural gas are flammable.
- LNG fires produce little or no smoke.

On contact with certain metals (such as carbon steel) LNG can cause immediate cracking. If spilled on the ground, LNG would "boil" (vaporize) very rapidly for 2 or 3 minutes until the ground was frozen and no longer emitted heat to the LNG. This would slow the rate of vaporization and minimize cloud formation dangers.

In the event of an LNG spill on water in a large-scale accident, it is unlikely that the water would freeze. Instead, the liquid would rapidly spread by gravity on the surface of the water. The water would continue to warm the floating LNG, vaporizing it and forming a spreading cloud. Researchers currently disagree on the shape, size, movement, and composition of the vapor cloud and the factors which will affect it. It is believed that the concentration of LNG vapor within the cloud is not homogeneous. Where the concentration falls within the flammable limits of 5 to 15%, the cloud may be ignited and burn back toward the source of the spill, where it will become an established flame burning over the spill itself, much in the same fashion as gasoline burns. It is generally agreed that, if the vapor from a large LNG spill ignites, it would be beyond the capability of existing firefighting methods to extinguish it (Society of Naval Architects and Marine Engineers, 1977). Therefore, the key to reducing the hazard of an LNG fire is a strong prevention program.

The potential hazards of transporting and storing LNG are widely recognized (DOE 1978). LNG can be dangerous if it is handled carelessly or if large amounts are released in an accident against which insufficient safeguards have been provided. Open-air detonation of LNG vapors is highly unlikely (Vanta et al. 1974, Lind 1975), even with extremely large ignition sources, including explosive initiators. However, detonation (i.e., explosion) of natural gas-air mixtures in enclosed spaces is possible if a sufficiently powerful ignition source is available. If a spill is not ignited quickly, the flammable vapor may be carried by the wind until a source of ignition is encountered. Experiments have shown that once the vapor has been ignited, a flame front burns back through the vapor toward the source from which the vapor came (Drake and Wesson 1976).

Except for the fact that LNG fires burn with the production of little or no smoke, they resemble fires from other burning hydrocarbon liquids in most respects. In general, an LNG fire burns at such a rate as to consume approximately 0.5 in. of liquid per minute. The LNG flame characteristics and the radiant heat fluxes near an LNG fire can be predicted based on the experimental data presently available (Katz and West 1975).

LNG inside a storage tank cannot burn unless it is vaporized and mixed with air. Only if it is released can there be a hazard. Storage facilities are designed and operated to prevent accidental release. The behavior of spilled LNG and an LNG cloud continues to be a critical area of concern to researchers of LNG spill phenomena.

4.0 BASIC FIRE AND VAPOR CONTROL PHILOSOPHY

Vapor dispersion and fire control practices are based on site-specific hazard and safety analyses of emergency conditions anticipated with operations involved in LNG production and utilization. Specifically, Title 49 Code of Federal Regulations, Part 193, § 193.1308 "Fire Control Equipment" requires that: "(a) each operator shall determine the types and sizes of potential fires within and outside each LNG facility that could affect the safety of the facility and the foreseeable consequences of these fires, including the failure of components or buildings due to heat exposure, (b) each operator shall provide fire control equipment and supplies to protect or cool components that could fail due to heat exposure from fires determined under paragraph (a) of this section and either worsen an emergency or endanger persons or property located outside the facility. Protection or cooling must be provided for as long as the heat exposure exists." Hazard analyses for five operations are typically considered:

- transportation (by either ship or truck tankers)
- gas treatment
- liquefaction
- storage
- vaporization.

An emergency condition is defined as any condition not under plant operator's control and resulting in a state requiring immediate action to:

1. Provide for the safety of the general public and of individuals on the plant site.
2. Prevent or control damage to facilities on the plant site or properties in the vicinity of the plant site.

In general, industry provides instructions (via manuals, classroom instruction and regular emergency procedure training) to prepare personnel for the actions necessary to cope with anticipated emergency conditions. Site-specific emergency preparedness manuals detail specific instructions and guidelines necessary to provide for the safety of individuals and the prevention or control of damage to property. In addition, those individuals charged with the responsibilities of execution of emergency actions are clearly identified.

Adequate emergency response strategies rely on effective vapor dispersion and fire control systems design. Operating personnel and experienced fire protection experts, working together with the design engineer, followed by an independent safety review, ultimately results in meeting minimum regulatory requirements. This sequential review process is illustrated in Figure 4.1. The figure shows that crosschecking at the design stage is integral to the review process. This checking includes vigorous review and audit by the quality assurance (QA) section.

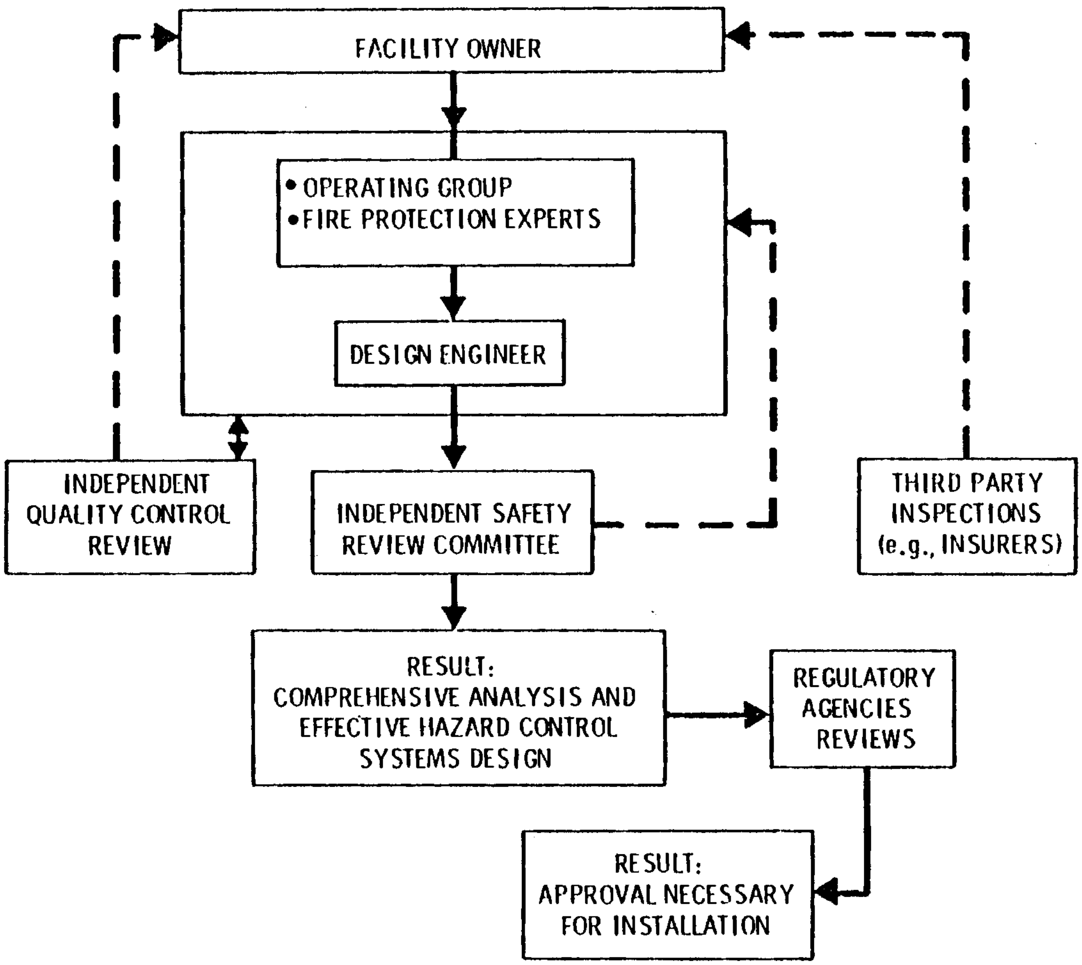


FIGURE 4.1. Control Systems Approval Process

Several non-hardware elements are essential to an effective F&VC system. An overall system must be designed to accommodate credible accident scenarios. Accommodation of these scenarios does not automatically imply extinguishment of fires and the elimination of vapor generation and dispersion. Devices intended to be applied to particular releases must be designed with compatible response times. A device designed to combat small LNG fires must be able to be applied while that fire is still small. If the response is too slow, the device may never be applied properly and will be essentially ineffective.

Logical facility layout is a major F&VC system design consideration. Facility planning needs to include sensor/detector arrangements that cover sensitive areas. In addition, the detectors need to be arranged such that they are tolerant of varying environmental conditions. Fluctuating wind direction, rain, fog, etc., can shield detectors from accomplishing their intended task. LNG facility layout also needs to accommodate the possible actions of emergency response personnel. Vehicle and personnel access to vital areas and equipment need to be assured through careful facility design.

The entire system should be tolerant of spurious alarms. Facility operators need to understand the limitations of fire and vapor detection and controlling devices. The F&VC system should be designed such that it can be expected to function properly; yet a cautious trust in the F&VC system needs to be established in the facility operators.

All or parts of certain facility fire and vapor control systems and services must remain in place and in service until all natural gas leaks and/or spilled LNG is either secured on the site or safely dissipated to the environment. The major LNG fire and vapor control systems and equipment that provide for personnel health and safety protection are presented in Table 4.1, together with the justification or functional consideration for each item. No attempt is made to list the items in the table by order of effectiveness or importance.

TABLE 4.1. Considerations Relating to LNG Vapor Dispersion and Fire Control

Item	Justification and/or Consideration
Valves in piping systems: 1) isolation (manual and auto) 2) pressure and vacuum relief	Limits size of leak (i.e., extent of a flammable mixture and the size of a fire).
Drainage channels and impounding areas	To direct and accumulate leaking LNG away from ignition sources and thermally damageable structures (both high and low temperature damage potential). If impoundment surface area is small, both the extent of the potentially flammable vapor cloud and the size of the LNG fire are minimized; however, even though a smaller surface area results in less evaporation, an uncontrolled, deep pool fire will burn longer.
Spacing between plant structures	Reduces the degree of involvement in fire and can reduce ignition potentials if structures contain ignition sources.
Outside lighting (including all emergency lighting, sirens and warning lights)	For manual leak detection at night. Although the white fog resulting from LNG spillage is usually quite visible in daylight, it is less visible at night without adequate illumination. NOTE: Lights should be explosion-proof and not be an ignition source and, of course, the LNG plant must be attended and/or patrolled routinely. Warning lights mounted as required to warn personnel of emergency situations.
Emergency power generator and/or battery-powered unit (uninterrupted power supply system)	Often, these units are natural gas-fired and fed from a separate, distinct natural gas supply line strictly for emergency use. The emergency unit(s) provides for operation of electrical equipment including detection, alarm, and secondary fire protection considerations and for public safety.
Communications systems	Facilitate and coordinate vapor dispersion and fire control activities both onsite and offsite.
Vapor and fire detection, alarm and monitoring systems and fire protection systems	Health and safety; also see "Outside Lighting - Warning Lights" item above.
Suits, masks, and other fire-fighting gear	Personnel safety
Mobile/portable fire-fighting equipment	Health and safety

5.0 FIRE AND VAPOR CONTROL TECHNOLOGIES

Currently used, commercially available fire and vapor control (F&VC) mechanisms are discussed in this section. The information presented is considered to be representative of the current U.S. state-of-the-art for detection, isolation, and fire control systems and techniques. Descriptions and details pertinent to specific active and passive systems came from engineering drawings, system manufacturer's and vendor's data, and the open literature.[a]

5.1 DETECTION OF FIRE AND VAPOR

LNG release control is concerned with limiting the quantity or effect of a release of LNG. Fire and vapor control systems are integrally linked by design to release detection systems. It should be recognized that some release detection equipment may be considered a part of the release control mechanisms because activation of the detection equipment may initiate control measures. This relationship between detection and control is illustrated in block diagram form in Figure 5.1. Integration of various F&VC components to form a representative F&VC system is presented in Figure 5.2. Also shown are several optional offsite related actions that may be associated with an LNG accident scenario. Some of the fire extinguishing and emergency shutdown systems shown in Figure 5.2 may be operated automatically, while others require operator action either at the scene of the release or from the control room. An integral feature of an emergency shutdown control system is that it must provide the capability to shut down the major items of equipment from a remote location during an emergency (see Section 6.0).

The purpose of a detection system is to monitor the environment in critical areas for releases of LNG, flammable gas, and/or certain characteristics of combustion--smoke, flame, and heat. Early detection includes the use of leak and fire detection systems coupled with warning devices. Complete fire protection and vapor control capability for manned LNG facilities include provision for manual notification of fire and vapor hazards. This is normally provided for

(a) This section is based in large part upon the references cited. These references should be consulted for more details on specific items of interest.

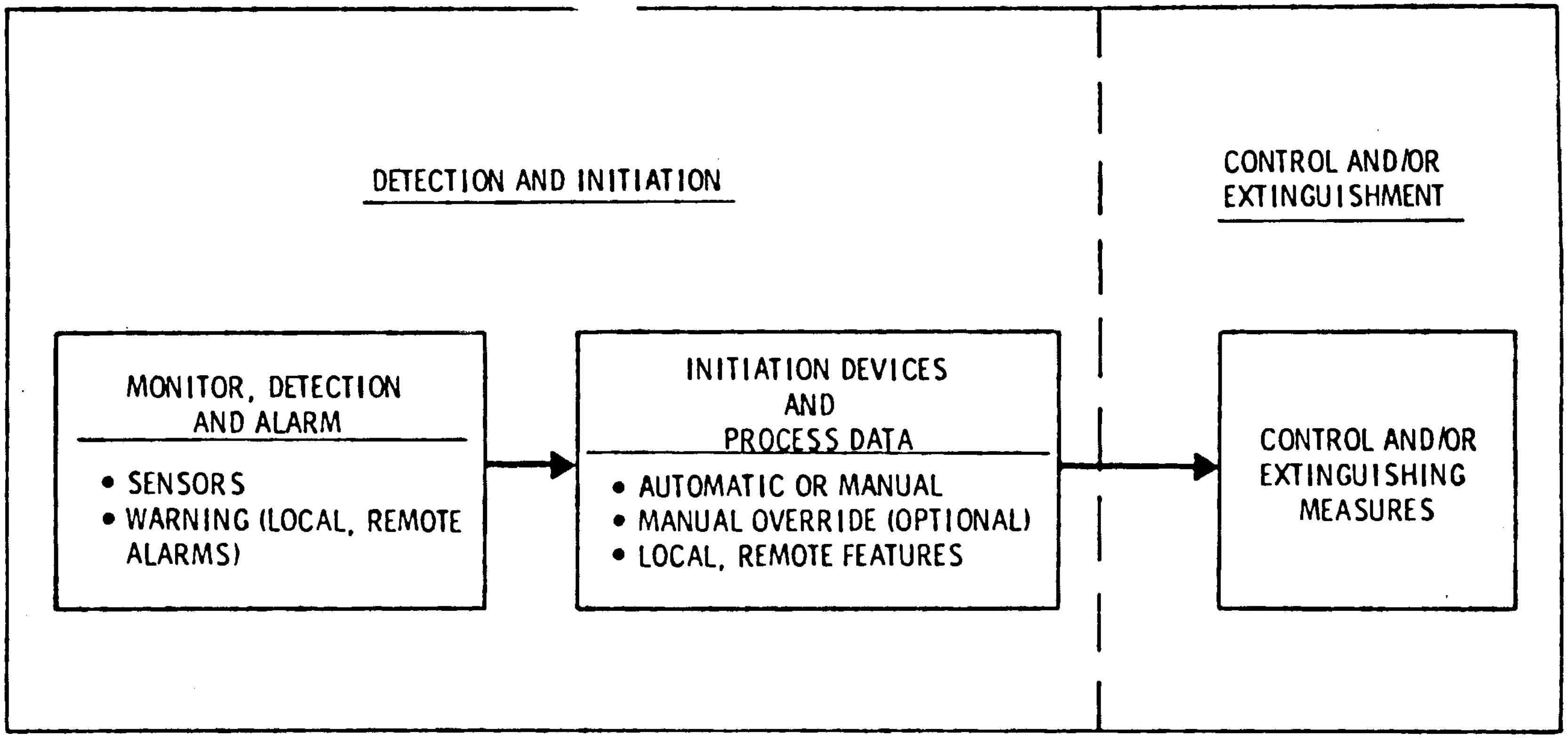


FIGURE 5.1. Detection and Control Relationship

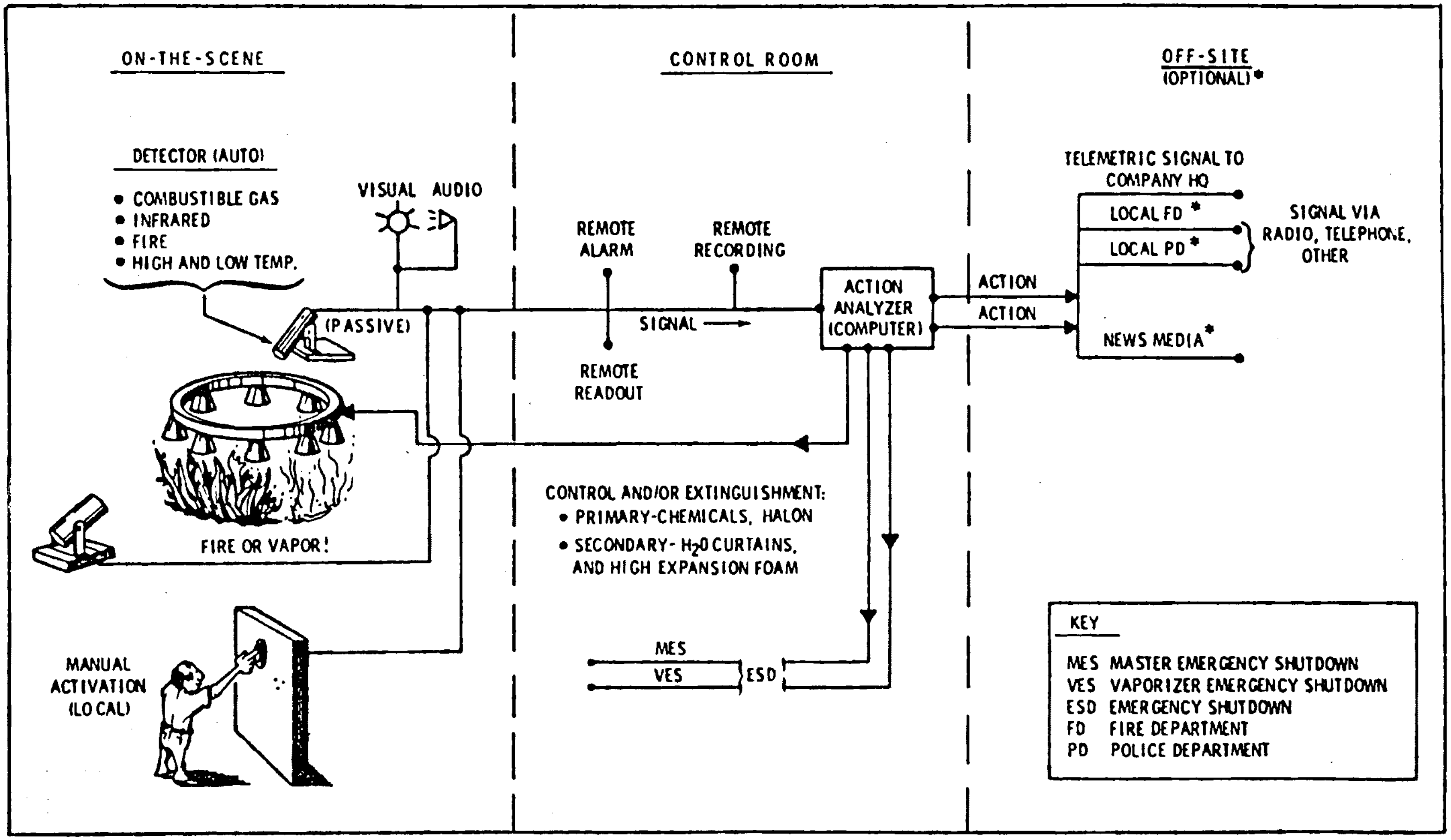


FIGURE 5.2. Representative Fire and Vapor Control System

via strategically located, manually activated fire alarm boxes. In general, these boxes are located along the most probable escape routes and are of explosion-proof design. Also, for continuously manned control rooms, two-way communication is an additional aid in the rapid notification of hazards. Well-trained and alert supervisory and operations personnel are essential ingredients of any manual notification apparatus. Upon detection of an abnormal condition, notification of that condition is imperative so that control measures can be initiated. The notification may be done by lights and alarms (both at the scene and remotely in a control room). In general, there are many sensing heads (detectors) of various kinds throughout the plant. The plant operator in the main control room must determine the specific location of an abnormal condition in order to initiate appropriate control measures. Depending on the system design, control measures may be either automatic or manual. Additional action activities are normally covered administratively by site-specific plant emergency procedures.

Detection systems are an integral component of safety systems and are used to energize control and/or extinguishment systems, shutdown processes (see Section 6.0) and to actuate alarms for both indoor and outdoor applications. The reliability of detection systems is an important factor in the safety of an LNG plant.

Detectors currently used have three common traits. They are reliable (based on experience), trouble-free, and provide rapid response to the specific trouble condition for which they were designed to monitor. Detectors fall into two general categories--leak detectors and fire detectors. Leak detectors, in turn, are of two types, those which detect the presence of spilled LNG, and those which measure the concentration of flammable gas in air. Fire detectors are designed to react to the characteristics of combustion--heat, smoke, visible light, or radiation (infrared or ultraviolet).

Characterization of the types of detectors currently used in the LNG industry is discussed in the following subsections.

5.1.1 Leak Detectors

Temperature detectors are generally used to detect spilled LNG by placing them in LNG drainage trenches or near LNG piping connections where leaks are most likely to occur. The basic types of temperature detectors are thermocouples and thermistors. Thermocouples relate electromotive force to temperature and thermistors relate electrical resistance to temperature. Thermocouples are also used to detect leaks in the inner wall of double-wall metal storage tanks by their placement at the bottom of the annular space between the two walls. Contact of LNG on the thermocouple results in a low temperature reading which in turn can be used to activate an alarm.

Both high- and low-temperature detectors are recommended for optimum protection (Zuber 1976). For example, upon detecting an LNG spill in a trench or spill basin, the low-temperature thermocouple detector system automatically actuates a foam system to quickly control vapor dispersion. In the case of a fire, the high-temperature detectors (see <u>Fire Detectors</u> in the following subsection for descriptions) automatically activates both the dry chemical system and the high expansion foam system. The dry chemical system rapidly extinguishes the fire, and the high expansion foam system assists in the fire extinguishment and/or reduces the ignition hazards of downwind vapor clouds.

Gas detectors are used to detect natural gas or methane concentrations in the atmosphere, especially in the lower flammability limit range. Commercially available gas detectors include thermal and conductivity meters, catalytic combustion meters, gas chromatographs, mass spectrometers, and infrared analyzers. The thermal conductivity meters operate on the principle that effective thermal conductivity of a gas mixture depends on composition of the mixture. Thus, hot film or hot wire techniques correlate effective thermal conductivity to varying concentrations of methane in air for a fixed sample flow velocity.

One type of catalytic combustible gas detection unit consists of a four-arm resistive bridge, of which two of the arms are coated with hydrocarbon reactive catalyst. The operating principle is that a catalytic reaction with a hydrocarbon produces heat which changes the effective resistivity of the coated arms of the bridge, thus correlating resistivity with methane concentration. When used outdoors, positioning of the detector is critical due to wind direction variations.

One of the more common combustible gas detection devices used employs a two-filament bridge circuit in which one filament is exposed to the environment and the other is exposed to a reference environment. In one device, the exposed filament is coated with a catalyst which combusts any flammable gas in the atmosphere. The resulting temperature rise of the filament changes its electrical resistance, creating an unbalanced bridge circuit which initiates an alarm. Another device using the bridge circuit utilizes the changing heat capacity of the atmosphere due to changes in the flammable gas concentration in the air. This causes a change in the temperature of the heated filament.

Gas chromatographs, mass spectrometers, infrared analyzers, and laser systems are used primarily to analyze test spill experiments. Gas chromatographs and mass spectrometers measure methane concentrations based on physical and chemical properties of the molecules of the gas mixture. Infrared analyzers operate on the principle that an electromagnetic energy is attenuated by passing through a gas sample. The amount of attenuation is related to the gas concentration. Laser systems seem to be very promising in determining methane concentrations. Laser systems operate on the same principle as infrared analyzers except with lower accuracy. The two-wavelength laser system seems to be the most accurate. Presently, these systems are not believed to be cost-effective for industrial use.

Some plant locations are ideally suited to a specific detector. For others, detector advantages and disadvantages with respect to the important factors of accuracy, response time, reliability, sensitivity to environmental factors (such as temperature and wind), cost, and convenience of application and degree of maintenance must be determined before final location selection is made.

Pairs of detectors are often used to monitor the atmosphere in the same general location--one near ground level and another somewhat higher in elevation. Since escaping methane (natural gas) density is lighter or heavier than air, depending on the temperature, this dual-detector application enhances prompt detection and alarm. Cognizance of anticipated atmospheric conditions or the nature of natural gas is essential to the optimum application of all detectors used at the LNG facility.

5.1.2 Fire Detectors

Fire detection systems currently used in LNG plants employ thermistors, ultraviolet (UV) detection instruments, and fusible plug systems. The thermistors can be used to measure either the absolute temperature or the rate of temperature rise. Ultraviolet detectors measure the intensity of ultraviolet radiation. Filters are used in these detectors to prevent visible light from activating the system. Most of the UV detectors can be activated by a welding torch and must be deactivated during welding operations. There are, however, UV detectors commercially available which can differentiate between UV radiation from a fire and welding torches, and do not need to be deactivated during welding operations. Fusible plugs utilize materials which undergo a phase change at a specified temperature, causing an alarm switch to trip. Smoke detectors are also used to detect combustion products resulting from a fire.

Ultraviolet detectors appear to be the most commonly used fire detectors. Most of the fire detecting systems have the capability of transmitting an alarm signal and a detector malfunction signal, and have a means for testing individual detectors in the system.

The operating characteristics of currently used fire detectors are presented in Table 5.1, together with typical applications and application limitations.

The successful continued operation of any detection device depends on:

- good design determined by careful review of intended use
- proper application for the intended use in a suitable environment
- correct installation and testing
- periodic inspection
- proper maintenance and testing.

In addition, the detector should be located so that it can quickly detect a fire and not be susceptible to false alarm.

Type of Detector	Operating Characteristics	Typical Application[b]	Controlling Parameters and Application Limitations
• Ultraviolet (Flame)	• These detectors see a narrow band of electromagnetic radiation given off by fire, arcs, sparks, as well as gamma and x-rays. Some types have "electronic sunglasses" so they ignore direct or reflected sunshine. Fast response; senses light at the extreme low end of the light spectrum.	• Used indoors or outside where a fire may first be expected to appear in the form of open flame or explosion. Generally teamed with gas detectors to protect indoor enclosed areas primarily from explosive mixtures.	• Like an optical unit, UV detectors must look directly at the fire to react. Generally an ultraviolet detector will react swiftly to the UV radiation from an x-ray machine or an arc welder. Heavy smoke will obsecure a UV detector. The buildup of ultra-violet-absorbing contaminants (oil, grime, salt) can cloud the UV detector lens, in effect, making it blind.[c]
• Smoke (Photoelectric)	• A long beam is directed at a photocell. Smoke obscures the beam, decreasing light transmission and sounding an alarm.[d]	• Generally restricted to indoor application; inexpensive method to cover a large area where a fire may be expected to generate smoke quickly.	• Sensitive to voltage variations. It needs some maintenance; the cell must be able to "see" the smoke to trigger an alarm, and dust or insect accumulation on the bulb or cell can limit the light, causing loss of sensitivity.
• Ionization	• This detector consists of a chamber with positive and negative plates and a small radioactive source material used to ionize the air within the chamber. The potential between the two plates causes ions to "flow" across the chamber, setting up a measurable current. Invisjble products of combustion suspended in air (aerosols, smoke particles) cling to the masses of moving ions, slowing them and increasing the voltage necessary for them to make contact. This imbalance is amplified by electric circuitry and triggers an alarm. Fast response.	• Generally restricted to indoor application especially for life safety and smoke control; for protection of areas of high value density.	• Air currents must carry combustion byproducts to the sensor.
• Thermal	• Generally two types: 1. Fixed temperature which reacts when area temperatures reach a preset degree setting. Fixed units may use a eutectic fuse that melts at certain temperature, or bimetallic element that warps, making (or breaking) electrical connection to alarm circuits. Some thermal sensors use a thermistor, which is a device constructed of solid semiconductor material whose electrical resistance decreases with an increase in temperature. An alarm circuit is completed when the resistance drops to a preset limit.	• Used indoors or outside where heat build-up can be expected to be rapid; also used in enclosed areas where no great life hazard is involved. Very reliable.	• Surrounding ambient temperatures are critical factor; these types of detectors can only detect the heat of a fire. Unfortunately, many fires are well along before significant levels of heat are produced and therefore thermal detectors are not designed to provide the invaluable lead time needed where control and/or extinguishment time is especially crucial.
	2. Rate-of-rise sensors react if area temperatures go up too fast. The sensor utilizes an air-filled chamber in which trapped air inside the chamber is vented through a tiny hole at an increasing rate as the temperature rises. If the temperature increases too rapidly, air cannot escape quickly enough and the pressure rises, pushing a diaphragm against alarm contacts. Another device is a line-type, air-filled tubing laced around an area that uses the rising temperature, increased pressure principle to activate an alarm.	• Primarily used indoors; responds quickly to a fast heat rise, for example 15 to 20 degrees per minute. • An unobtrusive, inexpensive line-type detector which can be used effectively for runs as long as 1000 feet or more; used on ceiling or high on walls.	
• Infrared (Flame)	• Reacts to heat given off by a fire. Fast response. Senses light at the extreme high and off the light spectrum.	• Used indoors or outside where a fire may first be expected to appear in the form of open flame or explosion.	• Also reacts to heat from sun, hot spots, people, lights, other sources; temperature, pressure, voltage changes can also trigger an alarm or interfere with the signal.
• Pressure	• A sensitive diaphragm which reacts to shock waves from an explosion.	• Generally used indoors.	

(a) Information contained in this table is derived from: Brown 1980, Offshore Magazine, and Manfredonia 1977.
(b) Detector application is based on the LNG plant-specific design after considerations of detector purpose (e.g., alarm, automatic fire extinguishment, and equipment shutdown or combinations thereof) and planned occupancy rate (i.e., manned or unmanned status).
(c) See Offshore Magazine; Detector Electronics has designed an ultraviolet detector with the test lamp inside the housing, but optically isolated from the sensor, that overcomes this problem.
(d) Tyndell effect photoelectric detectors use a beam of light in a chamber, with a photocell normally in darkness. When visible smoke particles enter the chamber, they scatter light and reflect it onto the cell. This causes a change in electric conductivity which results in an alarm.

TABLE 5.1. Fire Detector Characteristics[a]

5.1.3 Detection Systems Reliability

The reliability of F&VC detectors and systems is important in the overall design of LNG plants "because hazards often cannot be reduced by shutdown" (Federal Register 1980). The reliability of a given fire protection system depends on a complex array of factors, some of which are illustrated in Figure 5.3.

Several conclusions can be drawn from Figure 5.3. First, regulations provide guidance in the area of LNG fire and vapor control problems. However, the final system complexity needed to meet the minimum standards of safety and fire protection are determined by the LNG plant owner. A preoccupation by the regulator and the designer with the large-consequence, low-probability catastrophic events should not exclude the consideration of much higher probability, smaller consequence hazards associated with unplanned LNG releases.

Second, the more add-on features considered, the more complex and troublesome the system becomes. In general, complex systems require more maintenance and become increasingly expensive. In most cases, this increase in cost is borne by the consumer.

Third, redundancy has its limits and cannot effectively be extended infinitely without multiplying the overall complexity and creating further potential hazards. Human errors and common mode failures can be anticipated to increase as complexity increases.

Finally, the value and necessity of the preventive maintenance (PM)[a] program shown in Figure 5.3 should not be underestimated. There are two approaches for PM programs. One approach is the go-until-failure approach which advocates a minimal PM program. It is based primarily on increasing or maintaining production time by reducing the downtime (and costs) associated with maintenance or needed equipment replacement. The second and most prevalent approach recognizes that system reliability can be improved over the

(a) Preventive maintenance is defined as the planned inspection, tests, and/or overhaul made at predetermined, scheduled intervals to optimize operations time and operating performance.

APPLICATION

- Monitor
- Alarm
- Shutdown (e.g., process equipment and utilities, selected valves, and/or HVAC equipment)
- Automatic activation of fire extinguishing and/or vapor control systems
- Any combination of the above

DESIGN CONSIDERATIONS

- Design Basis Fire Stage[a]
  - Incipient - no visible smoke, flame or appreciable heat
  - Smoldering - visible smoke; no flame or significant heat
  - Flame - increasing heat anticipated with a possible reduction in visible smoke
  - Heat - large amounts of heat, flame and smoke; possibly toxic gases
- Quality Assurance - for individual components and the whole system; mandatory
- Power Supply:
  - Primary
  - Secondary (i.e., backup) must be uninterruptible:
    1) Battery (sufficient capacity)
    2) Diesel Generator (fuel capacity)
  - Loss-of-Power trouble alarm
- Installation and replacement features
- Maintenance requirements (degree and difficulty)
- Testing requirements (degree and difficulty)
- Redundancy (need, degree, and/or special features)[b]
- Environmental factors (e.g., earthquake, flood, sabotage, etc.)
- Explosion-proof capability
- Adequacy (i.e., spacing)[c]
- Interlock Features
- Time-Delay Functions
- Sensitivity[d]
- Location:
  - Indoors or outdoors
  - Manned or unmanned facility
  - Structural impediments (internal and external)
  - HVAC air movement flow paths
  - Human Factors Engineering (HFE) features[e]
- Provision for upgrading via design changes and modifications

REGULATORY REQUIREMENTS

- Federal, State, Local
- Accepted Codes
- Industry Practice

RELIABILITY

Fire and Vapor Control (F&VC) Systems

PREVENTIVE MAINTENANCE (PM) PROGRAM

- Degree or extent

DESIGN OPTIONS

- Disconnect alarm feature
- Detector/system malfunction alarm feature
- Self-check/test features
- Bypass Function (including out-of-service features)
- Security features (e.g., key-lock & glass enclosed)
- Automatic off-site alarm/communication feature

(a) The determination of the type of fire anticipated in a given location is an integral part of the selection process for the proper type(s) of detectors which are required for optimum reliability.

(b) For example, if two or more detectors (of similar or different types) are to be used, it may be desirable to have one set off an alarm only while any definitive, automatic corrective action occurs only when two or more detectors are activated.

(c) This important determination of what constitutes the adequate number (i.e., relative efficiency) of fire detectors for a given area to meet minimum safety standards is often left to the designer. He, in turn, relies on published vendor data, the NFPA publication No. 72E, Automatic Fire Detectors, and on his own experience and engineering judgement (an intangible entity).

(d) Directly related to footnote (c) in that the number of sensors required to attain the minimum standard of safety is to a greater or lesser degree dependent on their spacing which, in turn, may be a function or indication of their relative sensitivity.

(e) For example, is the readout monitor in the proper location on the control room panel for its assigned role and significance? Is it too high or too low? Is it blocked from view by something?, etc.

FIGURE 5.3. Considerations in Evaluating F&VC Detection Systems Reliability

entire plant lifetime by a conscientiously applied PM program. The latter approach seems more reasonable for fire protection systems because these systems can be usually maintained without shutting down the plant.

5.2 CONTROL OF FIRE AND VAPOR

Control of anticipated fire and vapor dispersion hazards is accomplished by both passive and by active techniques. The definitions of active and passive, as prescribed by Drake and Wesson (1976) are:

- An active technique for vapor dispersion control is one in which the operation of some equipment system is required following either automatic or manual detection of an LNG release.
- An active technique for control of LNG fire heating effects is one in which activation of equipment and/or manpower is required for exposure control.
- A passive technique for radiation control is one in which activation of equipment or manpower is not required and which is designed into and constructed as part of the basic LNG facility.

Passive techniques of fire hazard control begin with careful design of the facility to limit exposure of parts of the plant to potential fires in other parts of the plant (i.e., facility arrangement). The use of fireproof methods in plant construction, including fire-resistant coatings designed for both radiation and direct flames contact, are significant passive techniques. Detec-ors and warning devices can also be considered as passive devices since they are not applied to a vapor release or fire situation.

Active techniques, when employed and coupled with human activity, demand efficient, error-free operations to be safe and effective. The degree of efficiency ultimately achieved is directly related to proper training which realistically reflects on-the-job emergency situations. At most LNG facilities, it is impractical and potentially dangerous to conduct realistic firefighting training exercises onsite; rather, this instruction is relegated to recognized training centers. For example, the Texas A&M University Extension Service specializes in a dual program which couples on-campus classroom instruction with field exercises taught by qualified firefighting experts in LNG fire prevention and control.

All active techniques for vapor dispersion and fire control and/or extinguishment rely on adequate secondary fire protection (SFP) measures. A secondary fire protection measure is one in which a controlling agent is applied after an LNG spill. Fire prevention systems must rely on rapidity. Once an LNG fire starts and is allowed to enlarge, no system can put it out; it will burn itself out. Secondary considerations such as water curtains and deluge systems then serve to prevent or mitigate heat radiative damage.

Compliance with current standards (NFPA 1975) is a prerequisite for adequate SFP measures. It should be recognized that since SFP systems and methods must react to a wide range of conditions, their performance necessarily depends largely upon how well those conditions can be predicted. This wide range of conditions is reflected by the variety of active and passive F&VC mechanisms tabulated in Table 5.2. The list of mechanisms presented in the table is based on an analysis of the results of a survey conducted by the Institute of Gas Technology, which was prepared for the Energy Research and Development Administration (ERDA) in early 1978 (DOE 1978). The survey asked plant owners, among other things, to characterize their vapor dispersion and fire control systems. The characterization was to cover active and passive control mechanisms. Virtually every survey respondent, regardless of facility location or size, reported that they had incorporated by design various types of dikes, impounding walls and/or drainage channels as a passive F&VC measure at their facility. In general, these measures consist of compacted earth, concrete, metal, and/or other materials suitable for flammable liquid containment which conform to NFPA No. 30, Flammable and Combustible Liquids Code. It should be recognized that the use of enclosed drainage channels are prohibited in the U.S. because of the possibility of explosion if a flammable mixture is ignited within the enclosed area.

TABLE 5.2. Passive and Active Fire and Vapor Control Mechanisms

Rank[a]	Passive	Rank[a]	Active
1	Dike (100%)[b]	1	Dry chemical extinguishers (92%)[b]
2	Combustible gas detectors (79%)	2	Water hydrants (38%)
3	Ultraviolet flame detectors (75%)	3	Water extinguishers (29%)
4	Temperature sensors (42%)	4	Water sprinkler systems (27%)
5	Non-flammable coatings (29%)	5	High expansion foam (17%)
6	Smoke detectors (10%)	6	Water curtain (13%)
7	Fire resistive coatings (4%)	7	CO_2 systems (13%)
8	Low temperature detectors (2%)	8	Halon (halogenated hydrocarbon) (10%)
9	Closed circuit TV (2%)	9	Fire trucks (8%)
10	Direct phone to fire department (2%)	10	Water deluge guns (6%)
11	Fire alarm at fire department (2%)		
12	Radio to fire department (2%)		

(a) The ranking of the passive and active mechanisms in the table is based on an analysis of the results of a survey conducted by the Institute of Gas Technology as part of a study which was conducted for the Energy Research and Development Administration (see DOE/EV-0002 1978). Respondents included owner/operators of: 33 of 54 peakshaving plants, 12 of 23 satellite facilities, and 3 of 14 import/export facilities.

(b) All respondents to the surveys reported that they used impoundment areas of various sizes formed by dikes of various heights; that is, 33 of 33 of the peakshaving plants, 12 of 12 of the satellite facilities, and 3 of 3 of the import/export facilities (or 100%) of the survey respondents reported this mechanism was constructed at their LNG facility. Likewise, (79%) reported having combustible gas detectors, so it ranks second in the table as being representative of mechanisms currently in use, and so on for the rank shown for the remainder of the mechanisms.

For the satellite, peakshaving, and import/export LNG facilities, slightly less than 55% of the owner/operators responded to the survey. Unfortunately, the survey asked only general questions about what is installed at each facility. Therefore, no specifics were obtained about the number, size (physical dimensions), manufacturer or vendor, or operating characteristics. An extensive mail and plant-visit follow-up survey specifically designed to obtain this information would probably be quite useful.

It should be recognized that few LNG plants have, or are required to have under current regulations, all of the F&VC measures discussed in Section 6.0 for two reference LNG facilities, or those tabulated in Table 5.2. A partial explanation for the wide variance in application is the specific local considerations made in each case regarding the relevant concerns of safety systems.

Each of the mechanisms listed in Table 5.2 except for the leak detectors previously described in Section 5.1.1 and the fire detectors previously described in Section 5.1.2 are discussed in subsequent sections.

5.2.1 Passive Control

Pertinent features of passive mechanisms tabulated in Table 5.2 are discussed in the following subsections.

5.2.1.1 Dikes

A major passive design feature is the isolation system. Currently, two types of isolation systems for liquid spills and fire control are used--equipment shutdown systems and diking systems. Emergency shutdown systems are briefly discussed in Section 6.0. These systems relate more to release control than to fire and vapor control and are not discussed further in this report.

The basic limitation of both the dispersion and the radiation hazard at the reference LNG facilities is determined by site selection, distances from property lines to the inside surface of the dike, and the location of tank(s) and other equipment within the dike. In addition, significant factors in controlling the vapor dispersion hazard include:

- limitation of the boiling rate of spilled LNG by choice of dike face materials
- limitation of total vaporization rate by configuration of the dike floor
- design of the dike to have vapor holding capacity, either by oversizing the dike itself or by adding a tight vapor fence on the top of the dike.

Isolating an LNG spill within the diked area limits the total spill surface area, thus reducing potential fire hazards within the dike. This is accomplished primarily by varying the surface to depth ratio of a dike for a specific application.

Dike design is concerned with meeting all requirements for confinement to prevent the spread of the spilled LNG and/or vapor and fire to other critical components and to the general public located offsite. The dike must not fail in the worst case accident scenario anticipated for a spill. This is postulated as both the inner and outer LNG storage tank walls failing simultaneously at the tank base and thus creating a wave against the inner dike wall by the release of a full tank of LNG. The use of a dike around the impoundment area is designed to prevent an uncontrolled spill of LNG, as occurred in the Cleveland, Ohio, disaster in 1944 (Shank 1953, Elliot et al. 1946).

Dike Design Characteristics Affecting F&VC. It is known that the vapor generation rate from an LNG spill within a diked area is affected by the boiling rate and by the surface area covered by the spill. Also, the boiling rate decreases as the floor and wall surface areas cool. Since the vapors are negatively buoyant, optimum dike design would lead to an increase in the vapor hold-up time for the vapors that are generated early on. The increased hold-up time would, in turn, delay the vapor release rate to the atmosphere to a rate less than the peak vapor generation rate achieved while the floor and wall surface areas were cooling. Thus, the increased vapor hold-up time, in addition to the maximum vapor holding capacity afforded by the optimum dike design, could be anticipated to result in an overall decrease for any downwind vapor hazard.

LNG from a large rapid leak that contacts the non-cryogenic carbon steel outer wall of the storage tank could provide a mechanism for enhanced tank wall fatigue. This would probably increase the size of the leak and, subsequently, the potential for fire and vapor hazards. To reduce these hazards, drainage channels leading to lower elevation catch basins and diked impoundment areas are used at LNG facilities.

The dikes that surround LNG tanks may be increased in height in order to reduce the downwind concentrations by two mechanisms. High dikes reduce the area covered by LNG spills and therefore reduce the rate at which the vapor is injected into the atmosphere. The reduction in the boiling rate reduces the distance to which the flammable concentration can reach downwind from the LNG pool.

In addition to having less floor area per volume capacity, which reduces vaporization rates, dikes with high walls allow negatively bouyant vapors to attain neutral bouyancy more rapidly than do low-wall dikes. This occurs because the descent time of the vapors down the outside of the dike wall is greater and because the entrainment and mixing of the vapors with air is taking place both from above and below. The vapors escaping from a low-wall dike, on the other hand, lay nearer the ground and the air from above is primarily responsible for any mixing and dilution.

If the impoundment area is kept small, both the extent of a flammable vapor cloud and the size of the potential LNG fire are minimized. The duration of both may be increased, however, since the small area and high dike wall will result in a deeper pool. High-walled dikes would contain the spill or fire but would probably hinder efforts to stop the leak and/or fire extinguishment.

A dike floor which is slightly sloped outward and away from the LNG storage tank will facilitate dewatering and provide a means for reducing vaporization rates associated with LNG spills. If the LNG spill is rapid enough to allow for accumulation despite vaporization, the LNG will cool the dike floor and flow in the direction of the slope. If the rate of the leak does not decrease, the LNG will continue to accumulate against the dike wall, building a growing pool of LNG. To a point, such a pool will have less of a surface area than a similar pool accumulating on a flat dike floor. Thus, a lesser evaporation rate is to be expected. Evaporation rates for the two designs approach equality only when the surface area of the growing pool of LNG reaches the equivalent surface area provided by a flat dike floor of the no-slope design. Compartmentalized dikes, sometimes call diversionary dikes, are discussed in the literature (Drake and Wesson 1976), but no dikes of this type are reported currently in use by survey respondents (DOE 1978).

Several criteria for the design of the impounding system are provided in NFPA 59A. These criteria are not repeated here. In addition, Code of Federal Regulations Title 49, Section 193 (49 CFR 193 1980) specifies the storage capacity for the impoundment areas. This ruling takes into consideration the control of vapor generation and dispersion in defining the boundaries of an exclusion zone around the impoundment area based on the lower flammability limit for the vapor. It also provides for alternate planned vapor control measures in lieu of a dispersion exclusion zone under specific circumstances; in effect, making dike design options available.

Dike Surface Materials. The thermal properties of the dike surface materials are an indirect but important design consideration for fire and vapor control. For example, for a given LNG spill, sealed surfaces will generally have lower vapor generation rates than compacted soils, whereas crushed stone will probably have larger vapor generation rates because of the increased surface area of the irregular-shaped stones. Dike materials currently used range from soils (including sands) of various moisture contents to concrete, to compacted soils, to rocks of various shapes and sizes. Other more exotic materials have been tried in order to control the LNG boiling rates (Reid and Smith 1975), but no successful application outside the experimental arena was located in the literature.

Insulating concretes are reported to have boiling rate reduction factors of 10 to 20 times those of moist compacted soils (A. D. Little 1974). To remain effective, the concrete must be sealed against moisture. Drake and Wesson (1976) report that the practical problems associated with the application of insulating concrete to vertical surfaces remain only partially solved.

Polyurethene as a dike insulation material has shown some potential (Battelle Columbus Laboratories 1974). Its usefulness is limited, however, because it must be sealed against moisture. Complete bonding is difficult and therefore cannot be assured, and protection against damaging sunlight is necessary. In addition, polyurethene coatings may be difficult to maintain and are somewhat fragile by nature.

5.2.1.2 Coatings

Coatings for exposure control (both non-flammable and fire resistive) are intended to provide heat insulating protection for plant structures and equipment whose failure would contribute to a fire. Such failures are due to reduction in the strength of metals or the buildup of pressure in enclosed equipment at elevated temperatures and are classed as secondary failures. Fire-resistant coatings are designed for both radiant heat and direct-flame contact. In general, two types of fires are considered: impinging and non-impinging. The following summary, extracted from Uhl et al. (1972), accurately describes these two types of fires, including the anticipated areas for concern:

"Impinging types of fires occur when high-pressure levels exist and/or when the fire or escaping stream impinges upon structures, vessels, etc. Restricted escape of vapors will ordinarily result in such a jet type of fire, if ignition occurs. Characteristically, the fire will not tend to spread away from the source of the leak.

"Tank or spillage or roof gas fires, on the other hand, are usually of the non-impinging type. Such non-impinging fires will requires less extinguishing agent for effective control than will an impinging fire fed at the same fuel rate.

"In process areas, fires should be anticipated from LNG or refrigerant spills from high-pressure pumps or transfer lines, from leakage of lubrication oil, etc. In storage areas, fires should be anticipated at vents as well as at tank roofs, from spills in diked areas, etc. Around vaporization equipment, high-pressure leakage is again the dominant consideration.

"An LNG fire is most likely to be a low-pressure, non-impinging type of fire, however, similar insofar as burning characteristics are concerned to a low-pressure natural gas fire."

Passive protection such as insulation has been shown to give effective fire protection for periods greater than 2 hours for continuous fire contact. Equipment outside the fire will seldom show damage from radiant heating if the insulation is properly applied (Katz and West 1975).

In general, those items containing liquid hydrocarbons will be protected by an intumescent mastic for up to 2 hours. Concrete fireproofing will be required for protection beyond 3 hours (Schmidt and Chelton 1978).

Since the LNG flame characteristics and the radiant heat fluxes near an LNG fire can be fairly accurately predicted based on presently available experimental data, the reported usage of coatings shown in Table 5.2 seems unreasonably low. Cost-benefit analysis undoubtedly plays a major role in determining whether or not to insulate and, of course, to what extent. If the thermal radiation intensities at a given plant have been estimated based on safe separation distances for various materials, then coatings for exposure control, in addition to either water deluge systems or fire walls, can be designed into the plant for cooling objects anticipated to be exposed to fire.

Characteristics of commonly used fire-resistant materials are presented in Table 5.3, together with typical applications, application limitations, and controlling parameters.

One problem not completely covered in the literature (Schneider 1978) was the effect of cryogenic thermal shock that may be associated with an LNG fire. Similarly, whatever exposure control material is used, it may be subjected to exposure to LNG (submersion or liquid spray) while simultaneously being exposed to LNG and flames (Wesson 1975).

Characteristics for an ideal fireproofing material (Kayser 1973) include:

- ability to hold the substrate below 100°F for 1-1/2 to 2 hours in a continuous exposure to at least 1800°F at the insulation surface
- non-hydroscopic and a good weather barrier
- ability to accept some tension, stress, and flexing without cracking or debonding
- light in weight (50 lbs/cu-ft or less)
- hard-surfaced enough to withstand moderate impact loads
- non-corrosive to the substrate
- applicable with a low velocity spray apparatus with limited overspray
- weatherproof and corrosion resistant for long exposure periods to the installed environmental conditions.

In the past, if heat flux levels could cause a hazardous condition, either deluge systems were installed for all critical exposures or coatings were applied for exposure control. Occasionally both systems were designed into the plant fire protection system. More recently (February, 1980), new federal requirements (49 CFR 193) require operators of LNG facilities to determine the effects on components not normally exposed to extreme cold from contact by LNG or cold refrigerant that could result from error, a spill, or other emergency. Further, it requires the determination of the effects on components (including their foundations or support systems) of the extreme heat which could result from an

Type of Material	Characteristics	Typical Application	Controlling Parameters and Application Limitations
• Intumescent Mastic Compositions Note: The most common of the intumescent compositions are a modified vinyl, heavy-bodied mastic containing inorganic fibers in an aromatic solvent blend and a reinforced epoxy, two component, 100 percent solids (no solvent) spray system.	• These compositions act by absorbing heat in a chemical reaction which generates a foam-char system on the flames exposed side. Additional heat is used to drive the liberated gases through the matrix. The foam-char system also have an effective insulating effect; all of these factors being used to keep the protected sub-strate below its maximum allowable temperature.	• The available testing results using the ASTM E-119 Test Method indicate that using a 8WF31 beam temperature of 1000°F as the degree of fire protection criteria, a 1/2" thick coating of a typical intumescent mastic will provide "two hours" of protection, a 3/8" thick coating of epoxy-based intumescent will provide "two hours" of protection, and 1/4" thick subliming coating will provide "two and one-half hours" of protection.	• A disadvantage of the intumescents appears to be the propensity of the active ingredients to leach out during prolonged periods of exposure to outdoor environmental conditions. Once this leaching has occurred, the protection time provided by these type coatings are significantly reduced.
• Hydraulic Cement Compounds[c] (Includes: concrete, gunite,[d] and similar concrete base compounds)	• Ordinary portland cement concrete will withstand temperatures of 200°C with little or no loss of strength. Properties go down about 50% at about 500°C; disintegration begins at 540°C-650°C. Refractory concrete (e.g., high alumina cements) serves effectively at temperatures from 315°C to 1315°C (even as high as 1800°C). Addition of steel fibers, either carbon steel or stainless steel, improves resistance to thermal shock and prolongs life by a factor of 5 or more.[c]	• Provides good fire protection systems for both radiation and direct flames contact.	• Generally, the compounds are quite heavy, expensive, in some cases corrosive, and exhibit poor mechanical bonding properties. Note: these application limitations are considered to be easily overcome by using proper design techniques.[c]
• Ablative Coatings	• The fundamental principle is to apply a coating that gradually erodes due to the absorbed energy input from a fire condition. To change the solid material into a gas requires heat energy that would otherwise be absorbed by the structure being protected. The temperature rise of the protected structure is retarded in direct proportion to the ablative coating thickness and its thermal properties. The incorporation of ceramic-like intumescents has resulted in a tough micro-porous char layer which provides additional insulating properties while most of the heat input is required for the physical transformation of the base material.	• These type coatings provide excellent fire protection for steel structures.	• The major drawbacks to these family of fire protection coatings appear to be the complexity of the application and its installed costs.
• Subliming Compounds	• The subliming compounds provide a protected structural temperature based on the temperature of sublimation for each particular compound, the thickness of the material, the applicable thermal properites and the degree and time of the fire exposure. Some of the commercially available subliming compounds are not adversely affected by prolonged exposure to cryogenic temperatures and flames, simultaneously.	• The subliming compounds form a very tough, esthetic compound which is very tightly bonded to the steel structure to be protected. Some LNG facilities are using the subliming compounds for protection of carbon steel structures that are subject to LNG submergence and/or LNG spray impingement as well as direct contact with flames from LNG spill fires.	• (b)

(a) Information contained in this table is extracted from Drake and Wesson 1976 and Refractory Concrete 1978.
(b) No data were available for LNG fire tests of these coatings; it seems generally recognized that the existing data can be applied to passive fire protection measures required for LNG facilities.
(c) Personal communication with Charles H. Henager, Sr., Pacific Northwest Laboratory, August 14, 1980.
(d) Gunite is a form of shortcrete. Shotcrete is defined by the American Concrete Institute as "mortar or concrete pneumatically projected at high velocity onto a surface." Gunite is a term often used to designate the mortar type of shotcrete using only fine aggregate.

TABLE 5.3. Characteristics of Commonly Used Fire-Resistant Materials[a,b]

LNG or other hazardous fluid fire. Where the exposure (cold or extreme heat) could result in a failure that would worsen the emergency, the component/foundation/support system must be: 1) made of material or constructed to be suitable for the extreme temperature to which it could be subjected; or 2) protected by insulation or other means that will delay failure due to extreme temperature in order to allow adequate time to take emergency responses.

5.2.1.3 Closed Circuit Television

As shown in Table 5.2, only about 2% of the survey respondents indicated that they had installed closed circuit television (CCTV). The use of CCTV at two reference LNG plants is covered in Section 6.0.

Currently, CCTV is used primarily as a supplemental monitoring device by control room personnel to observe operations-related functions, including LNG truck loading operations, general observation work, the detection of spills and leaks and other safety hazards, and as an aid in facilitating and coordinating plant-specific work activities such as equipment repair and maintenance. It has been suggested (de Frondeville 1977) that CCTV (doubling for fire detection) might be advisable in certain areas at critical times as a special security measure to maintain operations-related surveillance of the plant equipment and to optimize monitoring for specific tasks. Therefore, greater use of CCTV to facilitate operation, to aid in fire detection and control, and to optimize security could prove to be cost-effective on a plant-specific basis.

5.2.1.4 Communications Systems

Communications systems (NFPA 1975) are required to be provided at loading and unloading locations so that operators can be in contact with other remotely located personnel who are associated with the loading or unloading operation. Specifically, communcations can be by telephone, public address system, radio, or signal light.

Many local codes (Allan et al. 1974) require automatic signals, with built-in time delays, as a means of communication with remote areas, including fire departments. The alarm-signal-delay feature allows operators to quickly diagnose the situation to eliminate spurious signals.

5.2.2 Active Control

The following subsections describe several active fire and vapor controlling agents. The discussions provide a general understanding of available active controls and tell how and where these controls are used. The emphasis of these discussions is on the controlling agent itself and not on the method of application.

When possible, the discussions will include information concerning how the control agent functions and what parameters might impact its effectiveness. An understanding as to how the agents work is beneficial so that the method of proper application can be better understood.

5.2.2.1 Dry Chemicals

Dry chemicals, such as sodium or potassium bicarbonate, are used to extinguish LNG fires. Part of the mechanism by which dry chemicals extinguish LNG fires is by absorption of the free radicals in the combustion chain. Thus, dry chemicals attack the flame and not the LNG spill. The minimum effective application rate of dry chemicals appears to be related to the average free radical concentration in the flame. Approximately 2 to 3 seconds are required for mixing before the dry chemicals begin to effect the LNG fire (Welker 1980). Reignition of extinguished fires is a problem with dry chemicals. While the chemicals attack the flames, they do nothing to reduce the vaporization rate or aid in vapor dispersion. Approximately 2000 ft^2 appears to be the largest fire that can be controlled by a manned dry chemical system (Welker 1980). Adverse wind conditions can greatly affect the minimum application rate required to extinguish a fire.

5.2.2.2 Water

One method of combating LNG-related releases is the use of water in the form of sprays, deluge guns, or water curtains. For most fires, water is a cooling agent which suppresses the generation of the flammable vapors from the fuel source. Due to the extremely low boiling point of LNG when water contacts the cryogenic fuel, the water serves as a heat source and creates an increase in the vaporization rate of the LNG spill. Therefore water should not be used in LNG fire extinguishment. One gallon of water at ambient conditions has enough energy to evaporate two gallons of LNG.

Water sprays are used in the LNG industry to:

a) aid in the vapor dispersion of spilled LNG
b) cool exposed equipment in order to prevent thermal damage
c) protect exposed equipment from radiation damage.

Spraying the LNG vapor with a fine water spray may induce vapor dispersion due to heat transfer from the spray to the vapor (Wesson 1974). However, the water vapor is not much warmer than the LNG vapor itself; therefore, the actual heat transfer may be small (Martinsen et al. 1977). The vapor dispersion may be primarily due to mechanical turbulence. The mechanical turbulence produced by the water spray may induce additional mixing of air into the vapor cloud.

Factors that may affect the efficiency of the spray as a means of vapor dispersion are:

- adverse wind conditions
- droplet size
- application techniques.

Because of its low cost and good thermal properties, water is used for exposure protection at several LNG facilities (see Table 5.2). It can be applied directly to the exposed equipment or applied as a water curtain between the fire and the protected facility.

When the water is applied directly for exposure protection, the water protects the equipment by absorbing thermal energy. For as long as a film of water exists on the equipment then the temperature of the equipment should not exceed the boiling temperature of water. A significant amount of water is used in trying to maintain this film.

Water curtain systems can attenuate radiant heat up to 30%. Enhanced performance appears to be obtained if the curtain produced is a fine spray. The curtain absorbs radiation heat flux. The smaller droplet sizes provide more surface area for heat transfer.

5.2.2.3 High Expansion Foam

High expansion foam is produced by passing pressurized water, containing a foam liquid concentrate, through a screen or grid. The size of the bubbles making up the foam is a function of several parameters, including the screen grid size. Bubble sizes are described using the output water volume ratio. These ratios commonly range from 200:1 to 1000:1. Foam is applied to LNG pools to reduce the downwind LNG concentrations and to reduce the size of LNG pool fires.

A reduction in downwind LNG concentration can be attributed to a warming of the LNG vapors as they rise through the foam and to mechanical turbulence near the foam. Both of these actions aid the dispersion of LNG vapors and therefore reduce the downwind concentrations. The application of the foam tends to increase the LNG vaporization rate by adding the heat content of the foam to the LNG pool. This happens when the foam breaks down as a result of direct contact with the cold LNG. The increase in evaporation rate is dependent upon the foam expansion ratio, as shown in Table 5.4 (Drake and Wesson 1976). The vaporization rate increase shown for the 1000:1 expansion ratio is based upon a limited amount of data and contains significant uncertainties.

The transfer of heat from the foam to the LNG pool will cause freezing at the foam water interface. The extent of freezing is not well-documented. Evidence of frozen layers of foam have been observed in some experiments (Welker 1980). It is expected that the frozen layers would retard the heat transfer to the LNG and act to reduce the evaporation rate.

Mechanical turbulance may also act to disperse the vapors from an evaporating LNG pool. This concept is not widely discussed in current literature and needs to be examined more closely.

TABLE 5.4. Vaporization Rate Increases

Expansion Ratio	Vaporization Rate Increase
500:1	0.14 in./min
750:1	0.10 in./min
1000:1	0.61 in./min

Should a fire appear before or during the application of the foam, the function of the foam changes from enhancing vapor dispersion to controlling pool fire size. The foam floats on the spill and restricts the rate of heat return to the LNG pool. Restricting the heat return reduces the vaporization rate as well as the size of the pool fire. The pool fire burning rate will be a parameter in establishing the effectiveness of the foam (Welker 1980). Application of foam during a pool fire will cause foam breakdown due to the heat of the fire and the cold of the LNG (Welker et al. 1974). If the foam is to be effective, a minimum application rate must be maintained. A depth of 3 to 6 feet for the foam appears to be necessary for adequate fire control. Strong winds may make maintaining adequate foam depths difficult. Foams can also be used to block radiant heat from reaching sensitive equipment.

5.2.2.4 Carbon Dioxide Systems

As shown in Table 5.2, carbon dioxide (CO_2) systems are used in about 13% of the LNG facilities that responded to the survey. The CO_2 system is generally found at an LNG facility in compressor buildings or around processes involving liquification or gas turbines. The CO_2 works by reducing the oxygen content in the air to a point where it will not support combustion. CO_2 in concentrations of 25% can suppress a fire but will not support life. Personnel must be evacuated from the immediate area when CO_2 is used.

5.2.2.5 Halogenated Hydrocarbons (Halon)

An effective control for extinguishing fires in an enclosed area is the gaseous form of the halon fire extinguishing agents. There are different types of halons, with Halon 1301 used primarily in the LNG industry.

Halon stands for halogenated hydrocarbons. It is not clearly known how halogenated agents work. Because they work so cleanly and efficiently, it is believed that they neither remove heat nor smother flame. It is possible that halon interferes with the chemical combustion process.

Halons are used in enclosed areas to maintain the level of the halogenated hydrocarbons in the atmosphere necessary to extinguish the fire and prevent reignition. Unlike dry chemicals, halons are not hindered by directional application constraints. For halons, it is only necessary to maintain adequate atmospheric concentration.

The use of Halon is expensive as compared to other extinguishing systems. From a cost stand-point the expense of a halon system can only be justified for an area of high importance.

6.0 DESCRIPTION OF FIRE AND VAPOR CONTROL SYSTEMS AT LNG FACILITIES

This section provides brief descriptions of representative LNG peakshaving and import facilities. Each description contains emergency shutdown system features as they relate to fire and vapor control, including operator interface. Typical locations for fire and vapor control systems and other fire protection equipment are described. The descriptions presented are representative of large, present-generation LNG facilities.

The primary objective of this facility description is to give the reader an idea as to how the FVC devices and methods discussed previously actually relate to an LNG facility. These representative facilities also provide a base case for more detailed evaluations of fire and vapor control. More detailed information on the operations, transportation, gas treatment, liquefaction, storage, vaporization, and process equipment can be found in an overview assessment of LNG release prevention and control systems scoping documents for these plants (Pelto et. al. 1982). Much of the following material was extracted from this study.

Not all LNG facilities of a specific type are designed the same, nor do they have the same fire protection needs. In fact, plants of similar design may not use the same fire protection measures. The differences in fire and vapor control designs between LNG facilities are due to the type and size of hazards anticipated, the physical arrangement of the plant, the type of plant operation, as well as the local and state codes defining minimum safety standards which differ from one location to another. Regardless of the reasons, it should be recognized that not all LNG facilities will contain all of the fire protection measures described in subsequent sections for the two reference LNG facilities.

6.1 PEAKSHAVING FACILITY

A plot plan for the representative LNG peakshaving facility is shown in Figure 6.1. All the major pieces of plant equipment are shown, including the various fire and vapor control features. Key facility features to note from this plot plan include:

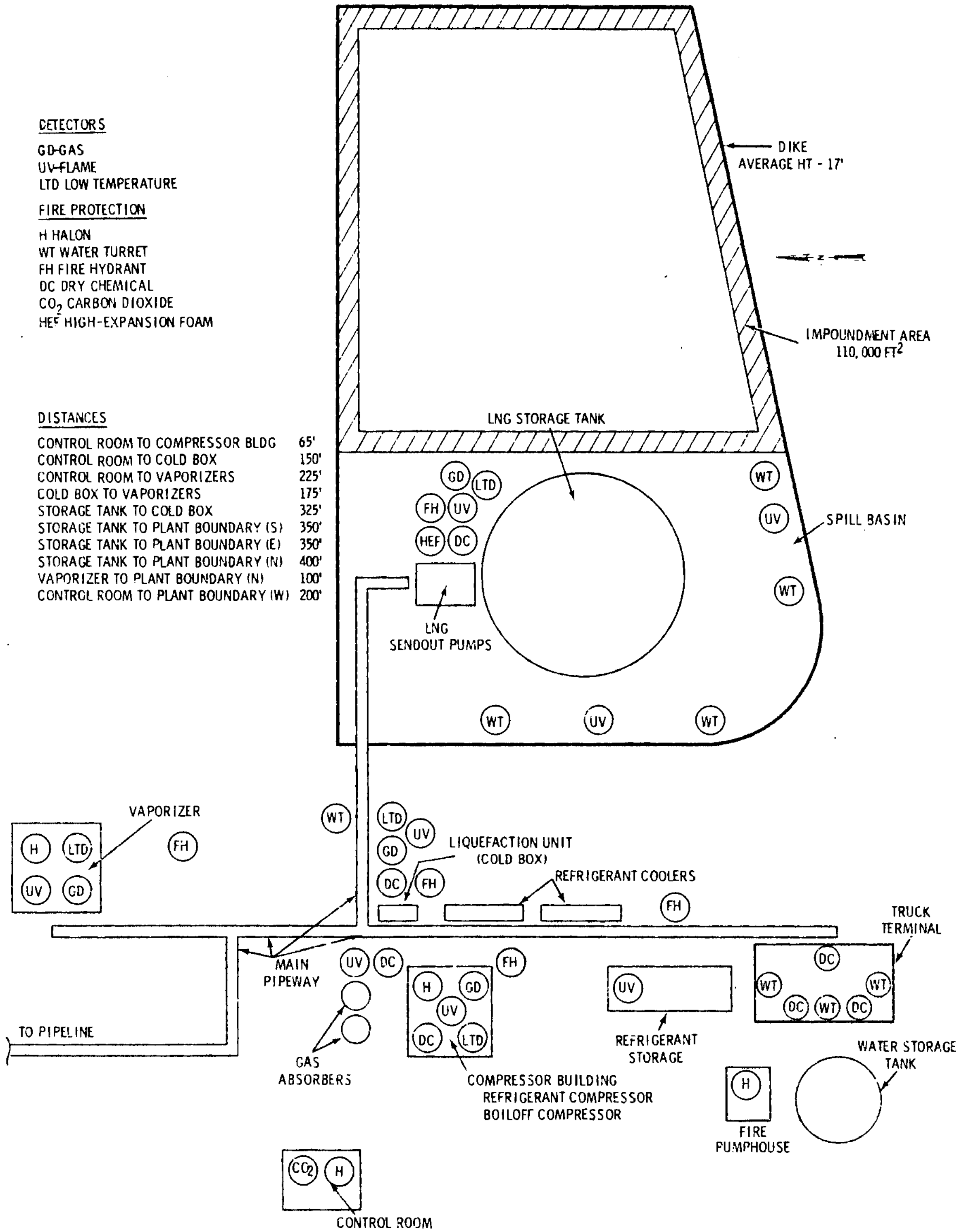


FIGURE 6.1. Representative LNG Peakshaving Plant - Plot Plan

- storage tank impoundment area--110,000 ft^2
- average dike height--17 ft
- minimum distance from storage tank to plant boundary--350 ft
- minimum distance from major equipment (vaporizers) to plant boundary--100 ft
- minimum distance from storage tank to major equipment (cold box)--325 ft.

The LNG storage tank is equipped with two 12-in. pressure relief valves which vent to the atmosphere. In the event of an underpressure, gas from the pipeline is brought back into the tank. If this is insufficient to prevent underpressure damage, two 12-in. vacuum relief valves admit air to the tank. The storage tank and sendout pumps share a spill basin that drains into a diked impoundment basin. The dike walls average 17 ft in height. The impoundment basin is capable of holding about 480,000 bbl, or 1.37 times the capacity of the storage tank.

Combustible gas detectors, UV flame detectors, and temperature sensors are located throughout the plant area. In the event of off-standard conditions, these detectors activate alarms in the control room. They can also be set to automatically activate the emergency shutdown system or the appropriate fire control and extinguishment system. The following subsections provide general information concerning these systems, together with a brief discussion of the representative peakshaving plant operation and operator interface as they relate to fire and vapor control.

6.1.1 The Emergency Shutdown System

The Emergency Shutdown System (ESD) has two circuits: the Master Emergency Shutdown (MES) and the Vaporizer Emergency Shutdown (VES). Both systems can be activated either automatically by detectors or manually by plant operators at the control room and at the two plant exit gates. From the time of initiation it takes about 30 seconds to place the facility in an emergency shutdown configuration.

The MES can be activated automatically by the ultraviolet (UV) fire detectors that monitor the following areas (see Figure 6.1 for locations):

1. compressor building
2. vaporizers
3. refrigerant storage
4. LNG pumps
5. piping on or adjacent to pipe racks next to compressor building
6. cold box
7. absorbers
8. regeneration heater.

When activated, the MES automatically initiates the following actions:

1. Electrical supplies to all nonessential plant circuits de-energize.[a]
2. Valves at the plant boundaries close to isolate the plant from the pipeline. These valves include:
   - natural gas feed to plant
   - gas from vaporizers
   - boiloff gas from storage tank
   - fuel gas to vaporizers.
3. The LNG tank and dike are are isolated from the remainder of the plant by the following:
   - valves at the LNG pump suction and the interior tank outlet close
   - the valve on the liquid inlet line from the liquefaction unit closes
   - LNG pump motors shut down
   - block valves between the LNG pumps and the vaporizers close.
4. A telemetric signal, "MES Tripped," is transmitted to the company's head office.
5. With loss of instrument air, all control valves go to their failsafe positions.
6. Gas from all gas handling equipment and lines vents through the relief header to the vent stack.

(a) Essential plant electrical equipment (e.g., fire pumps and fire and gas detectors) remain energized.

When activated, the MES system is intended to limit the size of a release. However, if the system fails and a manual shutdown is required, a much larger release can occur.

The second shutdown system, the VES, allows the rapid shutdown and isolation of all LNG sendout systems. The VES may be automatically activated, if desired, by a temperature sensor in the vaporizer gas outlet line (low temperature), by the UV flame monitors on the vaporizer burners (burner flameout), or by the water bath level indicator (low level). When activated, the VES automatically initiates the following actions:

1. Vaporizers shut down.
2. The following natural gas valves at the plant boundaries close:
   - gas from vaporizers
   - fuel gas to vaporizers
3. LNG sendout pump motors shut down.
4. Block valves between the pumps and the vaporizers close.
5. Pump section valves and the interior valves on the liquid withdrawal lines close, thus isolating the pumps from the LNG storage tank.
6. Gas from all gas handling equipment and lines vents through the relief header to the vent stack.

Combustible gas detectors are located around the LNG storage tank to detect any combustible gases descending from the vent. Gas is normally vented only in the case of an emergency shutdown. In an emergency, the storage tank is isolated from other equipment by block valves on the inlet and outlet lines which are activated by either the Master Emergency Shutdown or the Vaporizer Emergency Shutdown system.

The MES and VES circuits are energized with 120 VAC power from a separate "Uninterruptable Power Supply" (UPS) unit that maintains these systems energized and ready for operation. When these circuits are de-energized (fail-safe), the emergency shutdown actions described above are initiated.

6.1.2 Fire Protection Features

The fire control system consists of fixed and portable dry chemical fire extinguishers, high expansion foam systems, Halon systems, and a fire water system. Automatic venting and isolation systems help prevent the accumulation of flammable gas mixtures in enclosed areas and facilitate extinguishment of fires. The high-expansion foam system in the one-hour spill basin is shared by the LNG storage tank and sendout pumps. It can be activated automatically by low-temperature detectors or UV detectors, or it can be operated manually.

The fire extinguishment systems for the following enclosed areas, the vaporizer building, the compressor building, the LNG pumpout area, and the storage tank relief valves are all activated automatically by UV fire detectors. Combustible gas detectors initiate alarm only; but by plant design change, they can be connected to trip specific F&VC mechanisms, if required. All other equipment for fires and for control of vapor generation and dispersion must be operated manually.

The spill basin drains into a trapezoidal-diked area located to the east of the storage tank. The area of this impoundment basin is 110,000 ft^2 and the dike walls average 17 ft in height. The basin can hold about 480,000 bbl of LNG, or 137% of the capacity of the tank. All structural steel in the diked area is coated with an insulating, fire-retarding concrete.

The following detectors, alarms, and fire protection equipment are located in the LNG pump area:

- combustible gas detectors
- low-temperature detectors with alarms in the control room
- Halon fire extinguishing system
- UV fire detectors that automatically activate the Halon system and the Master Emergency Shutdown system (Section 6.1.1)
- 20# dry chemical fire extinguisher
- fire hydrant.

A UV fire detector and dry chemical extinguisher are located on top of the tank near the relief valves. The extinguisher, directed at the relief valves, is activated by the UV detector.

Descriptive features and functional considerations of the Halon system and the UV and gas detectors assumed to be used at the reference LNG peak-shaving plant are presented in Table 6.1.

The following detectors, alarms, and fire protection equipment are located in the liquefaction area:

- combustible gas detectors (see Table 6.1 for detector operation)
- low-temperature detectors with alarms in the control room
- UV fire detectors which automatically activate the Master Emergency Shutdown system (Section 6.1.1.1) and alarms in the control room
- 20# dry chemical fire extinguisher
- fire hydrant.

The refrigerant compressor is located in the compressor building (along with the boiloff compressor and adsorber regeneration compressor) next to the cold box. This building has the following detectors, alarms, and fire protection equipment:

- combustible gas detectors in each corner of the building
- low-temperature detectors with alarms in the control room
- Halon fire extinguishing system (see Table 6.1 for description)
- UV fire detectors which automatically activate the Halon system and the Master Emergency Shutdown system (Section 6.1.1)
- #20 dry chemical fire extinguisher
- fire hydrant adjacent to the building.

When the combustible gas concentration in the building reaches 25% of the lower flammability limit (LFL), an alarm in the control room is activated (see Table 6.1 for further details). High-rate ventilating fans turn on automatically to reduce the gas concentration. If the gas concentration reaches 60%

TABLE 6.1. Description of Selected Detectors Used at the Representative LNG Plant

Item	Description and Functional Considerations
Halon System	The fire extinguisher system in the vaporizer building is a Halon (halogenated hydrocarbons 1301 and 1212) inerting and fire extinguishment, total flooding system. This system can be used not only to extinguish natural gas fires but also to inert an enclosure and prevent an explosion. The Halon system is activated by UV detectors sensitive to the ultraviolet radiation from flames. It can also be activated by the combustible gas detection system. Activation of the Halon or other fire fighting systems requires simultaneous signals from two UV detectors located in the same area.
Combustible Gas Detector	Detectors respond to off-standard conditions by activating alarms in the control room. They can also be set to automatically activate the emergency shutdown system or the fire control system. Each detector has four indicating lights located on the control panel which denote the following conditions: 1. "Safe" condition 2. "Warning" condition, which signifies a gas concentration of approximately 25% of the LFL[a] of Methane 3. "Danger" condition, which indicates a gas concentration of approximately 60% or greater LFL (this condition also sounds an alarm) 4. "Trouble," which indicates a malfunction of the gas detection system The warning condition automatically activates a high-rate ventilation fan to reduce the gas concentration in the vaporizer building. If the danger condition persists, the fan is turned off and the building openings close automatically. The Halon fire extinguisher system then discharges automatically.
Ultraviolet (UV) Flame Detector	The UV fire detectors have very fast, adjustable (0 to 30 seconds) response times. They detect very small fires in any wind condition. However, there are some types of UV detectors (the earlier versions of UV detectors) that will activate by direct sunlight, artificial lighting or from welding arc reflections. Thus, these are subject to the practice of being turned off, especially when welding is being required near a UV detector. UV detectors use AC power and are thus sensitive to induced currents and power fluctuations. All burners are equipped with UV flame detectors that alarm in the control room in the event of flame-out. The UV detector can also be tied into the VES (see Section 6.1.1) to shut down the vaporizer in case of a burner flameout.

(a) LFL is lower flammability limit. Concentrations of 5 to 15% natural gas are flammable.

of LFL, another alarm in the control room is activated, the fans are shut down, building openings (louvered windows) are closed, and the Halon system is discharged, all automatically. The Halon floods the building and inerts the atmosphere.

6.1.3 Operation and Operator Interface

The control system for the representative peakshaving plant is designed for unattended operation in the liquefaction, vaporization, and holding modes. One operator is on duty each shift to monitor the plant and to adjust plant production or output rates as directed by the central office. All critical operating equipment and process variables are monitored for equipment malfunction or process upset. When the emergency shutdown system is activated, a telemetric signal, "MES tripped," is transmitted to the company's head office.

For scheduled startups, two operators are on shift; however, the plant is designed so that one trained operator can restart any portion of it after a shutdown, if all equipment is in proper working order. Visual and audio alarms indicate the nature of the problem that caused shutdown.

Major tasks, such as heatup and cooldown of the storage tank and initial filling and startup of the liquefaction system, require a significant number of additional operating and supervisory personnel. These operations are not automated and require close, continuous monitoring for safe operation.

Although plant operators are not traditionally viewed as plant components, they are essential to the proper operation and fire protection activities of the plant. The interface between operator actions and plant operations is therefore critical to release prevention and fire and vapor control.

Operators perform a number of diverse tasks at the reference peakshaving facility, many of which relate to release prevention and control (directly or indirectly) and to fire and vapor control (directly). During normal plant operations, the operators run the plant within set limits and standards to prevent conditions that may lead to releases. During offstandard conditions, the operators must respond appropriately to alarms, indicators, and other signals to prevent releases from occurring or to limit releases and/or fires in progress. Plant inspection and maintenance is also important to identify and remedy conditions that may lead to subsequent releases.

6.2 TRANSPORTATION AND TRANSFER SYSTEM

Specially designed truck trailers are used to transport LNG from the representative peakshaving facility. The trucks are inspected on a regular basis, and drivers are given a formal training program which includes instruction on the characteristics and safe handling of LNG. Equipment used to transport and transfer LNG is described in the following subsections, together with a brief discussion of truck loading and unloading procedures and fire protection features.

6.2.1 LNG Truck Trailers

LNG trailers are provided by design with a durable double-walled tank. The inner vessel is made of 5083 aluminum, with an outer vessel made of carbon steel. The outer shell and perlite insulation protect and cushion the inner shell and its contents. The trailer is designed to operate for up to 28 days without a loss of cargo. In the event of a fire, the carbon-steel outer shell retains its structural integrity and the insulation keeps the cargo cool for several hours. Figure 6.2 shows a cutaway view of one of the trailers.

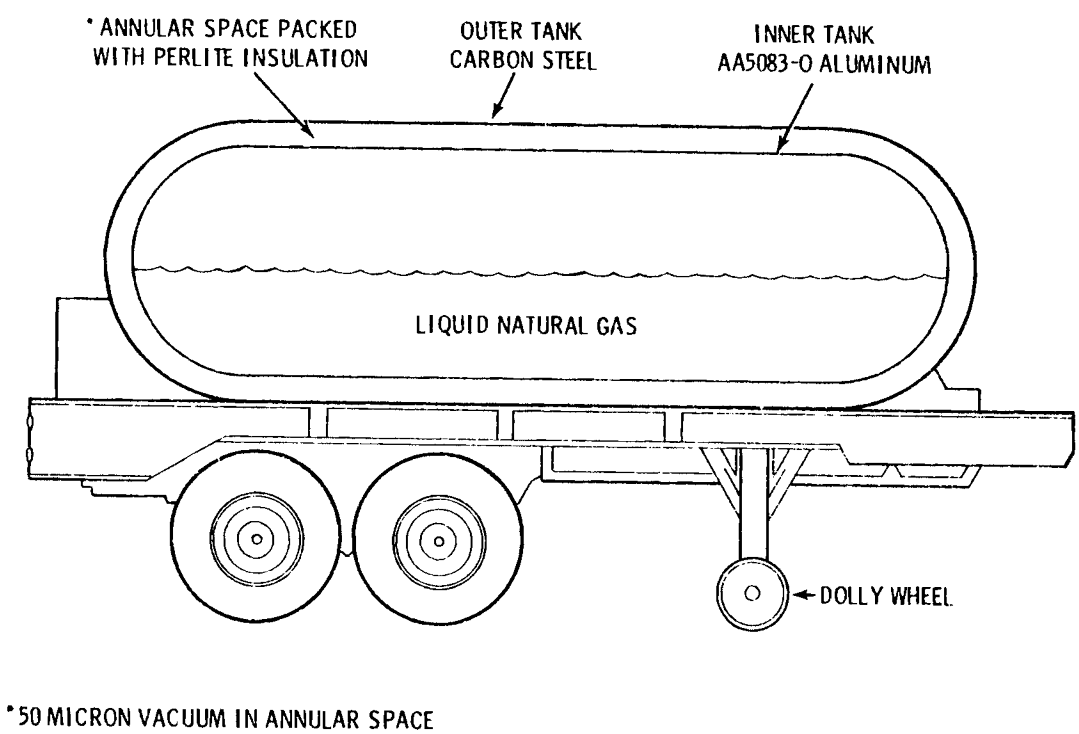


FIGURE 6.2. Cross-Sectional View of LNG Trailer

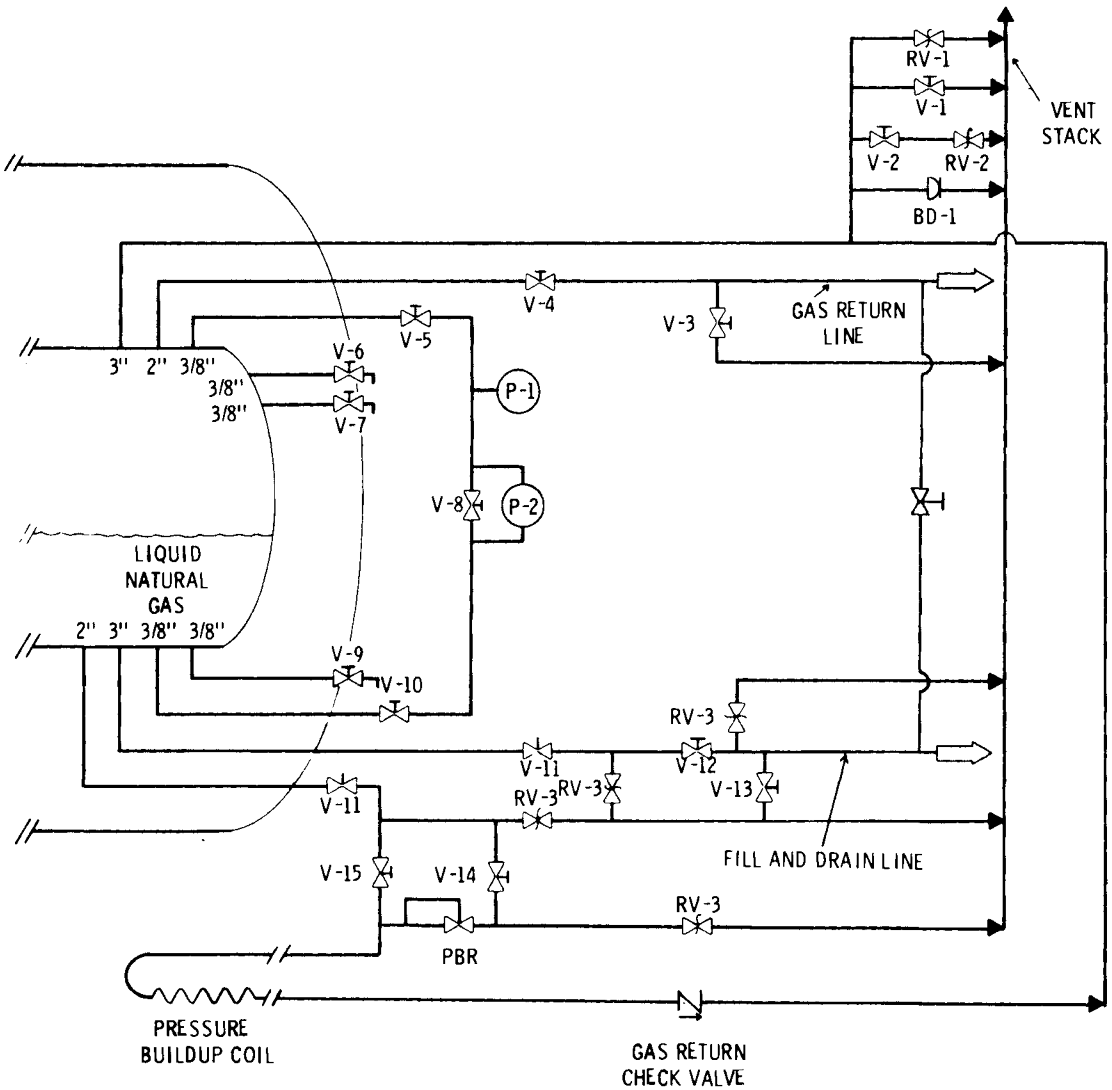
The annular space is filled with perlite and maintained at a pressure of 50 microns to insulate the inner vessel. The inner vessel is designed for a maximum working pressure of 70 psig but typically operates at only slightly above atmospheric pressure. The numerous pressure relief valves on the liquid and vapor piping all exhaust to a common elevated vent stack. Remotely operated shutoff valves are installed in the liquid lines. The trailer has a capacity of about 10,500 gal. and a length of 40 ft, and it weighs 21,500 lb empty and about 60,000 lb full.

The trucking terminal at the representative peakshaving plant is diked and trenched for spill retention. Trucks are loaded and unloaded through 3-in.- diameter flexible metal hoses which connect directly to stainless steel pipes at the terminal. The hoses are drained after each loading/unloading prior to disconnection. The peakshaving loading station consists of a weight scale, control panel for weight readout and valve control, and the pipes and valves necessary for loading/unloading operations.

Because of the relatively low density of LNG, the tank diameter is rather large (ID = 7 ft 4 in., OD = 8 ft). The large diameter results in a high center of gravity, about 9 in. higher than that of an LPG trailer. This results in an increased susceptibility to overturning accidents during collisions and high-speed turns.

Figure 6.3 shows the piping, valving, and instrumentation for the LNG trailer and the loading/unloading terminal. LNG trailers are equipped with numerous pressure relief devices, all of which vent to a common elevated stack. A burst disc prevents overpressurization. Remotely operated shutoff valves are installed in all liquid lines. A fusible link is included with the remote controls so that the valves will close in the event of a fire.

The trailer's main fill and drain line is a 3-in. line passing through the lower half of the shell. The line is equipped with a manual throttling valve, a remotely operated shutoff valve, and a line safety valve. A gas return line at the top of the trailer allows vapors to return to the storage tank during normal filling operations. A pressure buildup coil is provided to vaporize liquid during unloading and thus maintains adequate trailer



KEY:

HAND OPERATED VALVE
RELIEF VALVE
REMOTE OPERATED VALVE

V-1	VENT - 3"
V-2	ROAD RELIEF SHUTOFF - 1/2"
V-3	HOSE DRAIN - 1/2"
V-4	GAS RETURN - 2"
V-5	GAS GAGE LINE - 1/4"
V-6	90% FULL TRYCOCK - 1/4"
V-7	87% FULL TRYCOCK - 1/4"
V-8	GAGE BY-PASS - 1/4"
V-9	EMPTY TRYCOCK - 1/4"
V-10	LIQUID GAGE LINE - 1/4"
V-11	REMOTE CONTROL SHUTOFF
V-12	FILL AND DRAIN - 3"
V-13	HOSE DRAIN - 1/2"
V-14	PRESSURE BUILDUP REGULATOR SHUTOFF
V-15	PRESSURE BUILDUP - 2"
RV-1	INNER TANK RELIEF - 3"
RV-2	ROAD SAFETY - 1/2"
RV-3	LINE SAFETY - 1/4"
BD-1	BURST DISK - 3"
P-1	TANK PRESSURE GAGE
P-2	LIQUID LEVEL GAGE
PBR	PRESSURE BUILDUP REGULATOR

FIGURE 6.3. Flow Diagram for Trailer Loading and Unloading

pressure. Check valves in the pressure build circuit prevent the flow of gas from the tank through a leak in the coil. Three manual trycock valves also assist in loading and unloading.

6.2.2 Loading and Unloading

In general, trailers are filled by plant employees rather than by the truckers themselves. First, the trailer is inspected and, if acceptable, it is then weighed (to indicate the trailer liquid levels), chocked, and electrically grounded. Unless there is positive pressure from residual LNG, the tank is purged with nitrogen before filling. Liquid fill lines and vapor return lines are cooled with LNG up to the loading station and unloading valve. To fill the trailer, the operator connects the trailer to the loading station with a flexible high-pressure metal hose. The LNG is transferred to the trailer from the storage tank by the LNG sendout pumps. The actual trailer loading operations are controlled from a panel at the loading station. The transport terminal control system consists of the pump on/off control, manual valves on all three transfer lines, and a remotely operated shutoff valve into the truck loading line. The driver or loading station operator, while performing loading operations, can monitor all critical parameters (i.e., pressure, weight, etc.) associated with loading without leaving the loading station area.

Cold trailers are filled through the bottom fill line at about 350 gpm. A cold trailer requires only 1/2 hour to fill, while a warm one can take up to 4 hours. Weight scales provide the primary indication of a full load. The 87% and 95% full trycocks (see Figure 6.3) provide a backup indication. Boiloff vapors from loading the trailer are returned to the storage tank through a 2-in. vapor return line. Weight scales and two overflow trycock valves indicate the liquid level in the trailer.

When the truck is full, drain valves on the fill and vapor return lines are opened and the trapped LNG flows into a heated sump, where it is vaporized and returned to storage. The flexible lines are disconnected, and together the operator and driver verify the truck weight and the final valve positioning. The chocks and electrical grounding cable are then removed and the truck leaves the terminal.

Unloading is carried out in much the same way as filling. The truck is inspected and then chocked and electrically grounded. The trailer is connected to the terminal with a 3-in. flexible metal hose. Trucks can be unloading by pumping but are more often emptied by using the vapor pressure above the liquid. If the pressure is too low, a small amount of liquid is routed through the pressure buildup coil where it is vaporized by the ambient air and then routed to the top of the tank to provide sufficient pressure. Unloading proceeds at a rate of about 350 gpm and requires about 1/2 hour.

An automatic truck barricade prevents tanker movement until after the flexible hoses have been disconnected and properly stored. Without this barricade, a truck could attempt to leave the loading/unloading dock with the hoses still connected and thereby cause extreme damage.

6.2.3 Fire Protection Features

A total of 1700 lb of fire suppressant dry chemical is available at the unloading site in three fire extinguishing units (two stationery and one portable). In addition, three water turrets with multi-position nozzles are available in the transport terminal area. A closed-circuit television camera scans the terminal whenever a trailer is present, watching for liquid or vapor leaks. The spill retention system has the capacity to contain the cargo of a full trailer plus the holdup in the loading lines. As mentioned previously: 1) the area is graded so that spills flow away from the trailers, and 2) a fusible link is included with the LNG trailer remote shutoff valves controls so that the valves will close in the event of a fire.

Five events may initiate three automatic and two manual sequences which will stop LNG flow and place the station in a safe condition within 10 seconds should an emergency arise. The shutdown events are:

- fire
- loss of electrical power
- loss of pneumatic supply pressure
- LNG line rupture
- emergency manual shutdown.

6.3 IMPORT TERMINAL

A plot plan for the representative LNG import terminal is shown in Figure 6.4. This figure shows locations of major pieces of equipment and major components of the fire safety system. The fire and vapor control systems that make up the fire safety system are discussed in later subsections. Some key distances shown in the figure are:

- Ocean to plant boundary — ∿500 ft
- Ocean to nearest storage tank — ∿1,400 ft
- Storage tanks to plant boundary (south) — ∿500 ft
- Control room to nearest storage tank — ∿200 ft
- Control room to vaporizers — ∿60 ft
- Control room to compressor building — ∿100 ft

In addition, it should be noted that this representative LNG import terminal does not contain provisions for routine truck transfer operations of LNG. In other respects it is assumed to follow the conventional definition of a U.S. LNG import terminal. It is a large vaporization capacity (150 MMcf to 1000 MMcf of gas/day) facility which receives noncontinental U.S.A. LNG from oceangong tankers, stores it, and vaporizes it to supply base-load demands of the importing company. Storage capacities range from 3000 MMcf to 5000 MMcf of gas (140,000 m^3 to 235,000 m^3 of LNG).

Conversion of LNG to natural gas for ultimate sendout through the pipeline distribution network starts in the LNG storage tanks. Submersible in-tank pumps raise the LNG to 60 psig and transfer it to the secondary pumps. The 10 submersible secondary pumps raise the LNG to 1,300 psig and pump it to the vaporizers. The facility has a total of nine vaporizers. Five of these are seawater-heated and are used for normal operations. The other four are submerged combustion vaporizers and are used as spares for peaking operations. Gas leaves the vaporizers and enters the pipeline at 1,250 psig and 50°F. A block flow diagram for the entire process is shown in Figure 6.5, including postulated LNG and natural gas flow rates for both normal and peaking operations.

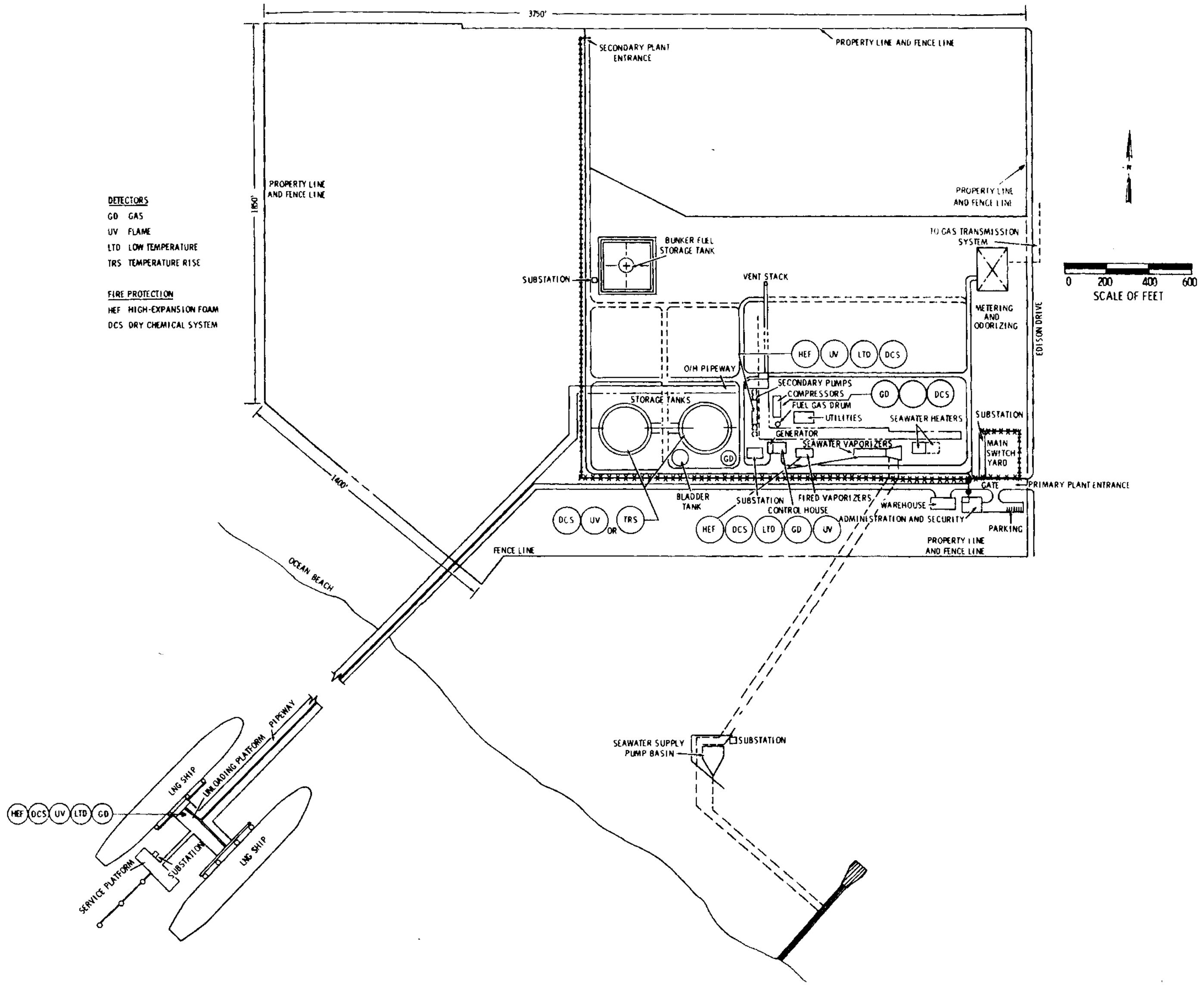
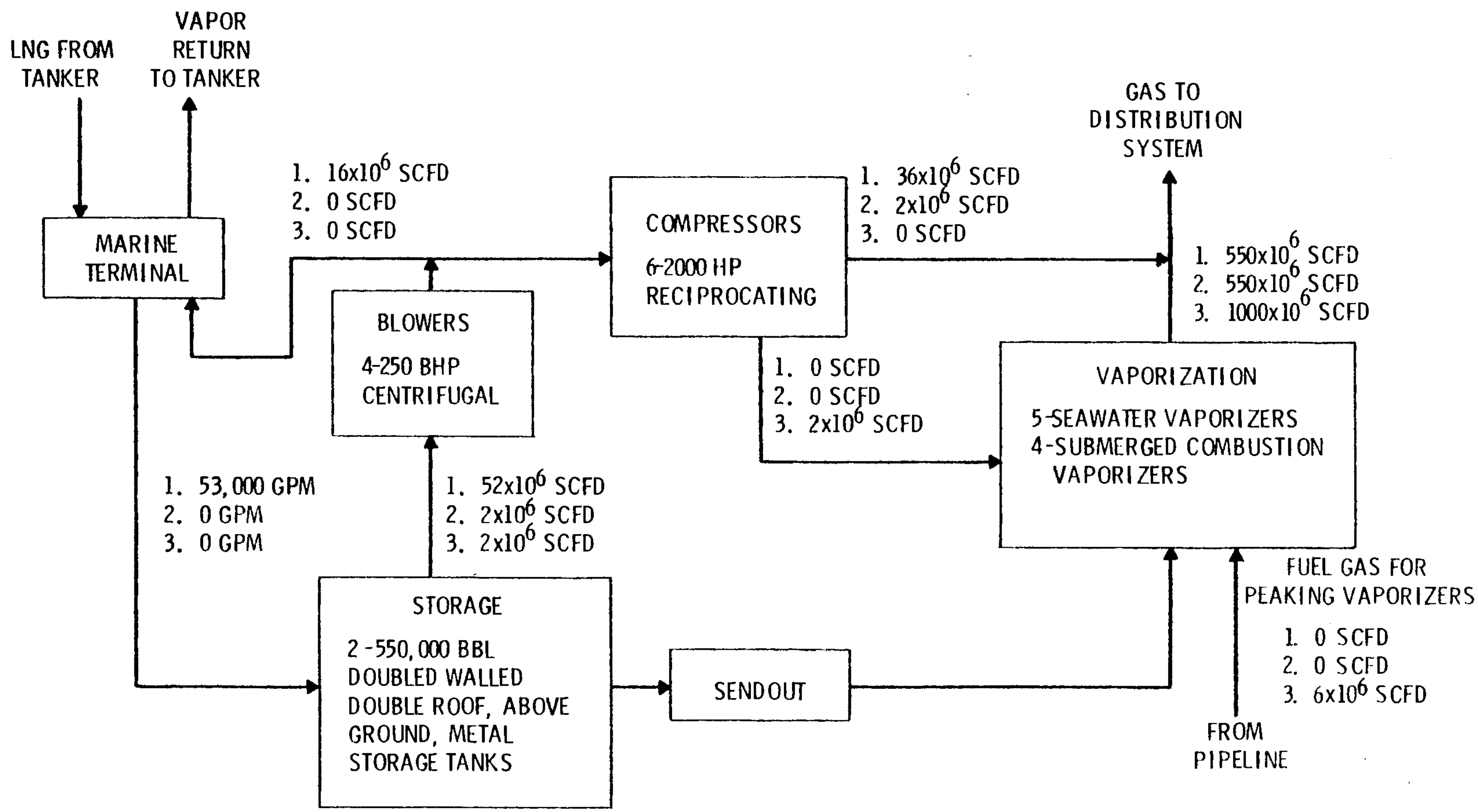


FIGURE 6.4. Reference LNG Import Terminal - Plot Plan



1. TANKER UNLOADING
2. NORMAL OPERATING CONDITIONS
3. PEAKING OPERATIONS, NO TANKERS UNLOADING

FIGURE 6.5. Flow Diagram for the Reference LNG Import Terminal

Combustible gas detectors, UV flame detectors, and temperature sensors are located throughout the marine and receiving terminal plant areas. In the event of off-standard conditions, these detectors activate alarms which indicate the exact location of a spill or fire on a graphic panel in the control room. They can also be set to automatically activate the emergency shutdown system or the appropriate fire control and extinguishment system. The following subsections provide general information concerning these systems, together with a brief discussion of the operation of the reference import terminal and operator interface as they relate to fire and vapor control.

6.3.1 The Emergency Shutdown System

The plant emergency shutdown system (ESD) has three shutdown circuits: the Master Emergency Shutdown (MES), the Vaporizer Emergency Shutdown (VES), and the Loading Emergency Shutdown (LES). These systems automatically shut down and isolate portions of the facility. In the case of the MES, the entire facility is shut down. It takes about 30 seconds to shut down the plant once the ESD is activated. The shutdown systems are activated by detectors located throughout the plant by certain process control variables or by the plant operator.

Both the MES and VES can be activated manually at the two exit gates. The MES is also operated automatically by the activation of ultraviolet (UV) fire detectors that monitor the following areas:

- compressor building
- vaporizers
- LNG pumps
- piping on or adjacent to pipe racks next to the compressor area
- unloading dock area.

When activated, the MES automatically initiates the following actions:

1. Electrical supplies to all non-essential[a] plant circuits de-energize.

(a) Essential plant electrical equipment (e.g., fire pumps and fire and gas detectors) remain energized.

2. The following natural gas valves at plant boundaries close to isolate the plant from the natural gas system:
   - gas from vaporizers
   - boiloff gas from the storage tank and ships
   - fuel gas to vaporizers.
3. The LNG tank and dike area are isolated from the remainder of the plant by the following actions:
   - Valves at the LNG pump suction and valves on the liquid withdrawal lines close.
   - Block valves on the tank inlet lines close.
   - LNG pump motors shut down.
   - Block valves between the LNG pumps and the vaporizers close.
   - Loading arm block valves close.
4. A telemetric signal, "MES Tripped," transmits to the company's head office.
5. With loss of instrument air, all control valves go to their failsafe positions.
6. Gas from all gas handling equipment and lines vents via the nitrogen-purged relief header to the vent stack.

Gas is not normally vented except in the case of an emergency shutdown. The terminal is designed to be operated without venting. Even in a case where the pipeline facilities are shut down, it will be possible to pack normal terminal boiloff gas into the line provided the first 10 miles are available. This would allow a complete terminal shutdown for at least 2-1/2 days before any venting would be required.

The second shutdown systems, VES, allows the rapid shutdown and isolation of LNG sendout systems outside the dock area. The VES may be automatically activated, if desired, by a temperature sensor in the vaporizer gas outlet line (low temperature), by temperature and flow sensors in the seawater lines of the open rack vaporizers, by the UV flame monitors on the submerged combustion vaporizer burners (indicates burner flame has gone out) and throughout the vaporizer area, by gas detectors in the area, or by the water bath level indicator (low level) on the submerged combustion vaporizers. It also can be activated manually from the vaporizer area as well as from the control room. Activation of the MES automatically activates the VES.

When activated, the VES automatically initiates the following actions:

1. The following natural gas valves at plant boundaries close:
   - gas from vaporizers
   - boiloff from storage tanks and ships
   - fuel gas to vaporizers.
2. LNG pump motors shut down.
3. Block valves between pumps and vaporizers close.
4. Pump suction valves and valves on the liquid withdrawal lines close.
5. Gas from all gas handling equipment and lines vents via the relief header to the vent stack.

The third shutdown system, LES, allows the rapid shutdown and isolation of all LNG sendout from and vapor return to ships. The LES may be activated by: UV fire detectors on the dock, low-temperature detectors, combustible gas detectors, power and air supply failure, high or low pressure in the transfer lines, excess flowrate, and tanker movements outside the established operating envelope.

In addition to automatic shutdown of the LES system, manual shutdown may be initiated from several locations in the unloading area, including the main terminal control room, the loading platform control room, and the ship's bridge.

When activated, the LES automatically initiates the following actions:

1. Block valves in the unloading arms close.

2. Block valves in the vapor bypass lines are prevented from opening or closing.
3. Block valves in the vapor return line close.
4. LNG transfer pump motors on the ship shut down.

The closing rates of the block valves and the sequence of shutdown are programmed to limit fluid hammer to within design limits and to keep LNG from being trapped between valves.

If operating properly, the LES system can limit and control the amount of LNG released. However, if this system is not operating properly and manual shutdown is necessary, a significant increase in the amount of LNG released can result.

In the event of a total power failure, the MES, VES, and LES circuits are energized with a battery power supply. After approximately 10 seconds, a 600-kW diesel-driven emergency generator provides the power to these systems. Firewater is provided during emergency shutdown through the use of diesel-driven pumps and/or city water pressure.

6.3.2 Fire Protection Features

The fire control system consists of fixed and portable dry chemical extinguishers, expansion foam systems, and a firewater system. Automatic venting and isolation systems help to prevent accumulations of flammable gas mixtures and facilitate extinguishment of fires.

As shown in Figure 6.4, the representative LNG import terminal consists basically of three parts: 1) the marine vessel; 2) the marine terminal and unloading dock; and 3) the receiving terminal, which consists of storage, vaporization and sendout. Each terminal requires its own unique fire protection system. Fire and vapor control features that make up these three systems are described in the following subsections.

Marine Vessel. Essentially the same types of fire and vapor control equipment used for in-plant fire protection are used on board LNG vessels. The U.S. Coast Guard specifies that each LNG tanker must contain a fire protection system comprised of the following:

- a dry chemical unit
- firewater for cooling and prevention of fire spread
- inert gas systems for engine compartments and certain other areas of the ship.

Katz and West (1975) report that current designs for all LNG tankers contain more dry chemical units than required by Coast Guard regulations. Those areas involved in LNG transport are primarily protected from fire through the use of dry chemical systems. These systems can be used to extinguish any fire on board that is small enough to be extinguished manually. Current LNG tanker designs also have monitor nozzles at strategic locations to provide greater range and powder delivery. Fires up to 2000 square feet in base area can be extinguished with these systems.

If an LNG containment failure can be isolated quickly, either manually or by the emergency shutdown system, damage to an LNG tanker will be minimal. Cryogenic fracture of hull and deck plates is of more concern than a small on-board fire. For this reason several LNG ship operators protect the deck by water flooding during LNG transfer operations.

Marine Terminal and Unloading Dock. The following detectors are located at the marine dock:

- gas detectors
- low-temperature detectors
- UV fire detectors.

Each of these are connected to an alarm and pinpointed by location and type in the main control room and the marine control room.

The fire extinguishment system at the marine terminal consists of the following:

- high-expansion foam system
- fixed dry chemical units
- one fire hydrant

- four dry chemical fire extinguishers, 2 each at the marine control tower and the fire hydrant station
- sprinkling system on the roof of the marine control room.

None of the fire extinguishing equipment at the marine terminal is activated automatically. It can be activated manually by local or remote means. Remote controls are located in the marine control tower or in the main control room.

The unloading platform towers are patterned after control towers at small airports and are reached by spiral stairs inside a 72-in. steel support cylinder. Each pulpit has a water-spray system, and the support cylinders are heavily insulated for fire protection. The entire structure is pressurized with fresh air. Comfortable temperatures are maintained by a heat pump.

A containment system is located under the platform area to hold spills from the loading arms. The low-temperature detectors are located in this spill area to indicate when a spill occurs. Containment is included for LNG transfer lines at the beach and plant area. The transfer system includes welded pipe connections rather than flanges to reduce leaks.

Receiving Terminal. Shore facilities consist of the LNG storage tanks and vaporization and sendout components.

Each LNG storage tank has a concrete dike wall having a capacity of about 1.3 times the capacity of the tank. The dike wall is approximately 81 ft 4 in. high, 1 ft 6 in. thick, and 259 ft inside diameter. The inside of the dike wall is lined with a 2-1/2-in.-thick insulating material to reduce the evaporation rate of LNG in the event of a tank failure. A 10-ft space separates the dike from the outer shell of the storage tank. The dike wall and the storage tank are supported on the same 4-ft-thick reinforced concrete mat. However, the dike wall surrounding each tank is not structurally tied into the foundation. This allows the concrete wall to contract freely in the event of a large LNG spill. A weather shield extends from the top of the concrete dike to the outer tank roof to keep precipitation from falling into the annular space. An air circulation system is installed to circulate ambient temperature air throughout the annular space. Withdrawal of cold air by this system prevents excessive moisture buildup, condensation, and ice formation in the annular space. A water pump is installed at the bottom of the annular space to remove any water that might collect there. High-expansion foam generation systems are installed in this area and can be activated either manually or automatically from low-temperature detectors located in the pump-out area. Also, UV fire detectors located in the pump-out area near the spill basin and at each pressure vacuum relief valve on top of the tank can activate chemical and expansion foam systems and shut down pumps and associated equipment, either automatically or manually. Combustible gas detectors located in the pump-out area sound alarms at 25% of lower flammable limit. At 65% of lower flammable limit, an alarm sounds and the sendout pumps are shut down, either automatically or manually.

Each of the LNG storage tanks is also protected by a fixed water deluge system with water applied only to the roof of the tanks because the walls of the main containment extend to the top of the outer shell of the tank. The excess water runoff from the water deluge system is carried across the annular space between the tank and the concrete containment and discharged down the outside of the containment wall. The deluge system is designed to deliver sufficient water to maintain the tank roof at safe operating temperature during the maximum fire that could be expected at the receiving terminal. Deluge water is provided by electrical pumps in addition to the city water pressure. A UV fire detector located near the tank relief valves automatically activates a dry chemical extinguisher aimed at the relief valves. Also, each storage tank area contains a manual fire alarm and two portable dry chemical fire extinguishers, each with a 30-lb capacity.

The secondary pumps (see Figure 6.4) are located in their own diked area, which has a dry chemical fire extinguishment system and high expansion foam system.

A fire truck containing a dry chemical system is used as a backup. Additional hoses and a small water pumping capability are also provided on the truck.

As mentioned previously, water is provided during emergency shutdown situations through the use of diesel-driven pumps and/or city water pressure.

The seawater vaporizer area and submerged combustion vaporizer area are continuously monitored by multiple combustible gas detectors, ultraviolet flame detectors, and low-temperature detectors. Each detector is hooked to an alarm and is pinpointed by type and location in the main control room.

High expansion foam units are located at the vaporizers and are activated either automatically or manually by low-temperature detectors (grade level), which also activates an alarm and automatically shuts down the vaporizers. The UV fire detectors have very fast but adjustable (within 30 seconds) response times that sound an alarm activating the dry chemical units for approximately 30 seconds and expending the supply. The high-expansion foam units are then activated to cover any LNG spills and limit the amount of vapor generation. Gas detectors in the area activate alarms at 25% of the lower flammable limit. At 65% of the lower flammable limit, another alarm sounds and either automatic or manual shutdown of the vaporizer follows.

In addition, fire hydrants supplied through underground pipes with spray monitors are located at the vaporizers. Manual fire alarm switches along with two 30-lb dry chemical extinguishers are also located in the area.

A fire truck is available to backup the dry chemical, water, and high expansion foam systems. This truck contains a dry chemical unit which connects to the vaporization system. Additional hoses and a small water pumping capability also are provided on the truck.

Pressure relief valves are located at the outlet and inlet portions of the vaporizers and set below critical levels for the equipment. Gas discharged from the pressure relief valves enters a nitrogen-purged collector system where it is conducted to the vent stack. An independent dike system is included to maintain any spills that might occur. A leak or rupture in any vaporizer inlet line releasing cold LNG could possibly cause failure of other components in the system that are not designed to withstand the extreme cold. A containment dike surrounds the vaporizer area to contain any spills that might occur there.

6.3.3 Operation and Operator Interface

After a ship is berthed at one of the two berthing facilities, LNG is pumped, using onboard ship pumps, through four 16-in. marine loading arms which combine to form a 42-in. transfer line at the unloading platform. The transfer line carries the LNG along a trestle to shore and then to the storage tanks. Normal transfer rate is 53,000 gpm. At this rate, tankers are unloaded in about 12 hours.

The loading arms are supplied with hydraulic power to control inboard, outboard, and slewing motion. They can be operated by one man from the master control panel in the control or by a portable remote control unit. Each arm is equipped with two sets of redundant sensing devices which initiate audible alarms and activate the emergency shutdown system whenever excessive motion is sensed.

Plant operators are essential to the proper operation and fire protection activities of the import terminal. They perform a number of diverse tasks related to release prevention and control (directly or indirectly) and to fire and vapor control (directly). During normal plant operations, the marine terminal control room is manned as long as any of the cryogenic arms are connected to the ship. The operators run the terminal within set limits and standards to prevent conditions that may lead to releases. The terminal operator has at his fingertips the controls for the arms, the vapor return system, firewater pumps, the dry chemical fire protection system, and all offshore valves. For communications, he has a direct line to all ships' cargo control officers, a direct line to the terminal main control room, radio, normal telephone, and a two-way loud-speaker system.

7.0 A SUGGESTED FIRE AND VAPOR CONTROL SYSTEMS EFFECTIVENESS EVALUATION PROCEDURE

This state-of-the-art review identified wide differences in the application of fire and vapor control systems throughout the LNG industry. A systematic effectiveness evaluation could be useful in the evaluation and solution of alternative fire and vapor control systems as necessary in response to changes in regulatory requirements, during the design of new facilities, or when upgrading older facilities.

The effectiveness of fire and vapor control systems involves both the reliability and the capability of the individual components as well as the entire systems. The reliability of a component is its ability to start on demand and operate for a required period. The capability is its ability to carry out its design functions. A capability analysis requires direct consideration of the functional parameters involved in device performance (e.g. temperature, LNG concentration, water pressure, etc.). This information is not always available and there are often gaps in understanding the physical and chemical phenomena involved. Component and system reliability is more easily addressed. The basic assumptions in a reliability analysis are that components are designed properly and when they operate, they perform as designed. Failure data under the specified operating or accident conditions are required to perform a reliability analysis.

Based upon the above considerations, the first step in a fire and vapor control system effectiveness evaluation should be to analyze system reliability. A phased approach which complements that proposed by Pelto et. al (1982) for release prevention systems is outlined below.

A list of representative release events would be identified and quantified in terms of frequency and release quantity. Those developed by Pelto et. al for typical LNG facilities could serve as a starting point. The behavior of the LNG following release would be modeled using spill, spreading, vaporization, and dispersion models. Difficulties may be encountered in applying available models and simplified assumptions will have to be made. Simplified event trees modeling the case of ignition and no ignition and the response of the pertinent fire and vapor control components (including the human interface) would then be con-constructed. These event trees would be quantified using the best available data and used to compare fire and vapor control system design alternatives. This analysis could identify potential weak links and information gaps. Key areas would then be modeled in more detail consistent with the potential cost/benefit considerations of the application.

This evaluation approach could be applied on a generic or facility-specific basis. The representative facilities described in Section 6 would serve as a base case for fire and vapor control system design comparisons and event tree analysis. Alternative fire and vapor control systems would be considered one at a time and compared with the base case. On a facility-specific basis, postulated release scenarios and the response of the facility's fire and vapor control systems would be modeled in as much detail as available data permits.

8.0 CONCLUSIONS AND RECOMMENDATIONS

This report has reviewed current state-of-the-art and industrial practices related to LNG fire and vapor control technologies. Typical applications, controlling parameters, limitations, and operational characteristics of commercially available fire and vapor control systems are described.

Because relatively few release LNG incidents have occurred, it is difficult to assess fire and vapor control system effectiveness on the basis of actual performance. Based on the excellent safety record of the LNG industry, current fire and vapor control practices appear to be adequate.

This state-of-the-art review identified wide differences in the application of fire and vapor control practices throughout the LNG industry. A systematic effectiveness evaluation (as outlined in Section 7) could be useful in comparing alternative fire and vapor control systems as new facilities are constructed and older facilities are upgraded. This evaluation could also provide assurance that the fire and vapor control systems continue to serve as an independent and reliable backup to release prevention systems.

This study identifies several key areas important to the successful operation of fire and vapor control devices. These include:

- good design determined by careful review of intended use
- proper application for the intended use in a suitable environment
- correct installation and testing
- periodic inspection
- proper maintenance and testing.

Other important considerations are quality assurance, preventive maintenance and human factor effects in all of these areas.

The back-up capability for fire and vapor control systems is typically provided by redundant components. If a device is the most appropriate choice for a particular application and back-up protection is desired, then, in general, a second similar device will be chosen as the back-up. This practice will increase the opportunities for common mode failures. Common mode failure analysis could be useful in identifying potential emergency situations that are presently not accounted for.

In general, variations in LNG facility designs are based upon different perceptions of costs and benefits. Information on system components costs is an essential part of a system effectiveness evaluation. System performance criteria are established to ensure the system components fulfill general expectations required by the system design. These requirements serve to increase confidence in system reliability and capability. It is recommended that cost/benefit analysis techniques be developed to provide additional criteria and guidance for the selection of fire and vapor control equipment.

The adequacy of a given LNG facility design is based on the surrounding population density, type and number of physical structures surrounding the plant boundaries, and proven and accepted fire protection technology and techniques. One or more of these parameters may change with time. These plant specific parameters should be analyzed periodically to determine the effects of changes on the area surrounding the plant and its current fire protection capabilities.

Similarly, the adequacy of training for actual emergency firefighting situations should be periodically assessed. The proficiency of firefighting personnel is probably best defined in terms of frequency and quality of training. Firefighters must have both the authority and the confidence to make on-the-spot decisions. Title 49 Code of Federal Regulations, Part 193, requires initial training in accordance with a written program and a written program of continuing instruction at intervals of not more than 2 years. The latter requirement is intended to keep personnel current in the knowledge and skills that they acquired from previous training sessions. Firefighting techniques and skills are learned through field exercises that cannot be taught or acquired in the classroom. Since firefighting is a learned skill and one that requires a high degree of proficiency to be successful, it is suggested that relearning this skill should take place at about the same frequency as other training which is required by 49 CFR 193. In addition, regulators would probably gain invaluable insights about the problems of fire and vapor control if they were to participate in field exercises and training.

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16. Abstract

The liquefied natural gas industry employs a variety of technologies to detect, limit and/or control the hazards of LNG vapor dispersion and fire. This assessment of state-of-the-art LNG fire and vapor control (F&VC) technologies was performed by Pacific Northwest Laboratory as part of the Liquefied Gaseous Fuels Safety and Environmental Control Assessment Program conducted by the U.S. Department of Energy, Office of the Assistant Secretary for Environmental Protection, Safety and Emergency Preparedness (DOE/EP). In this report typical applications, controlling parameters, limitations, and operational characteristics of commercially available FV&C systems are discussed. A representative LNG peakshaving plant and a representative LNG import facility are used to describe the F&VC systems. Information from vendors and the open literature were used to formulate descriptions of the systems and components. These descriptions are presented in a manner that facilitates their use in assessing current state-of-the-art and industrial practices. Also, where applicable, human interface with specific systems or equipment is described.

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