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LNG Facility Siting – An Alternative Approach for Vapor Cloud Reduction

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Abstract

The siting of Marine LNG facilities in the United States requires application of the Title 49 of the Code of Federal Regulations (CFR) Part 193, *Liquefied Natural Gas Facilities: Federal Safety Standards*[1], and NFPA 59A – 2001 Edition, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas* [2]. In addition, the guidance for LNG siting application available in the PHMSA (US DOT Pipeline and Hazardous Materials Safety Administration) web site is also required.

One of the most important items for LNG facility siting is the Hazards Analysis, which consists in the identification of the SALS (Single Accidental Leakage Source) by analyzing all piping in the facility. The SALSs for conventional piping are defined based on the size and length of the lines and the application of a failure rate table provided by PHMSA [3]. This methodology may generate scenarios with large flammable gas clouds, especially for long lines such as the LNG loading line and rundown line. Vapor barriers are a design solution acceptable by the regulators and commonly used to prevent vapor clouds from reaching a property that could be built upon [4].

This paper presents the application of Pipe-in-Pipe (PiP) technology for the LNG rundown line and the LNG loading line (which runs over a marine trestle). The Pipe-in-Pipe consists of an inner pipe designed for the process conditions of the particular service, insulation material wrapping the inner pipe, and an outer pipe. The outer pipe is designed to provide full containment in the unlikely event of a leak from the inner pipe and to withstand any thermal deformation due to exposure to cryogenic temperatures. Any leakage from the inner pipe is directed to the flare system.

With the application of PiP technology for the LNG loading line and rundown line, any potential leaks in the inner piping will be contained by the outer pipe and directed to a safe disposition. If approved by FERC and USCG, this technology will allow proposed LNG projects the potential for reduced flammable gas clouds, reducing the need for other mitigations, such as vapor barriers. Another advantage of the PiP technology is that any leak in the marine area will be contained by

the outer pipe, allowing the reduction of the liquid containment system for facilities with long trestles over water.

Introduction

The requirements for the siting of LNG facilities in the Unites States siting are regulated by FERC (Federal Energy Regulatory Commission) and DOT PHMSA (Pipeline and Hazardous Materials Safety Administration), to ensure that that the design will be safe for the plant personnel and the surrounding community. FERC is responsible for authorizing the siting and construction of onshore and near shore LNG import or export facilities [5].

The regulatory code that establish the siting requirements is Title 49 of the Code of Federal Regulations (CFR) Part 193, *Liquefied Natural Gas Facilities: Federal Safety Standards* [1], which includes NFPA 59A – 2001 Edition, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas* [2] by reference.

Below is a summary of the key siting requirements:

- Thermal radiation protection heat flux exclusion zone:
    a) 1,600 Btu/hr/ft^2 (5,000 W/m^2) at a property line that can be built upon for ignition of a design spill.
    b) 1,600 Btu/hr/ft^2 (5,000 W/m^2) at the nearest point located outside the owner's property line that, at the time of plant siting, is used for outdoor assembly by groups of 50 or more persons for a fire over an impounding area.
    c) 3,000 Btu/hr/ft^2 (9,000 W/m^2) at the nearest point of the building or structure outside the owner's property line that is in existence at the time of plant siting and used for occupancies.
    d) 10,000 Btu/hr/ft^2 (30,000 W/m^2) at a property line that can be built upon for a fire over an impounding area.
- Flammable vapor-gas dispersion exclusion zone:
    a) Any potential flammable gas cloud from a design spill at the concentration of ½ LFL (Lower Flammable Limit) cannot extend beyond the property line that can be built upon and that would result in a distinct hazard.
- Vapor cloud explosion exclusion zone:
    a) Vapor cloud explosions are modelled for the confirmed/congested areas.
    b) 1 psi overpressure cannot extent beyond the facility limits.
    c) LNG storage tanks must withstand any potential blast overpressure.
- Design spills are calculated for each line based on the PHMSA's Nominal Failure Rate Table, which is applied to determine if the threshold 3 x 10^{-5} failures per year is exceeded [3]. Then flammable gas dispersion, thermal radiation, and blast overpressure are modeled for the bounding scenarios. Section 2 has more details and examples.

One of the main challenges typically faced during the concept phase of an LNG facility project in the United States is to develop the Plot Plan in a way that the safety of the community and plant personnel is assured, it will comply with the applicable regulations, and the plot plan foot print is compatible with the project objectives in regard to land acquisition. The flammable vapor dispersion exclusion zone is typically the main constraint and is the primary focus of this paper.

1. Design Spill Criteria

The design spills from the LNG process and transfer lines are defined based on the criteria established by PHMSA for the Single Accidental Leakage Sources (SALS), based on the Nominal Failure Rate Table and the comparison with a threshold of 3×10^{-5} failures per year of operation (one failure every 30,000 years).

PHMSA's Nominal Failure Rate Table is available on its web site [3], and is based on published failure rates. The table provides the failure rates for piping equivalent hole sizes based on the length and diameter of the piping.

There are four categories for the equivalent hole sizes:

- Catastrophic failure (full bore rupture).
- 1/3 of the pipe diameter.
- 10% of the pipe diameter, up to 2 inches.
- 1 inch.

The duration of the selected releases is defined as 10 minutes.

2. Challenge with Long LNG Pipe Runs

The challenge with PHMSA's failure rate and pipe size criteria is that long LNG pipe runs and large pipe diameters will lead to large calculated flammable vapor clouds foot prints.

As an example, depending on the layout of a multi-train LNG facility with marine loading the length of the rundown lines (lines from the LNG trains to the LNG tanks) and the loading lines (lines from the LNG tanks to the loading berths) can be several thousands of feet, which will typically result in either 1/3 of the pipe diameter failure scenario or a full bore rupture being the controlling design case. Figure 1 has a depiction of the rundown lines and loading lines for a hypothetical marine LNG facility.

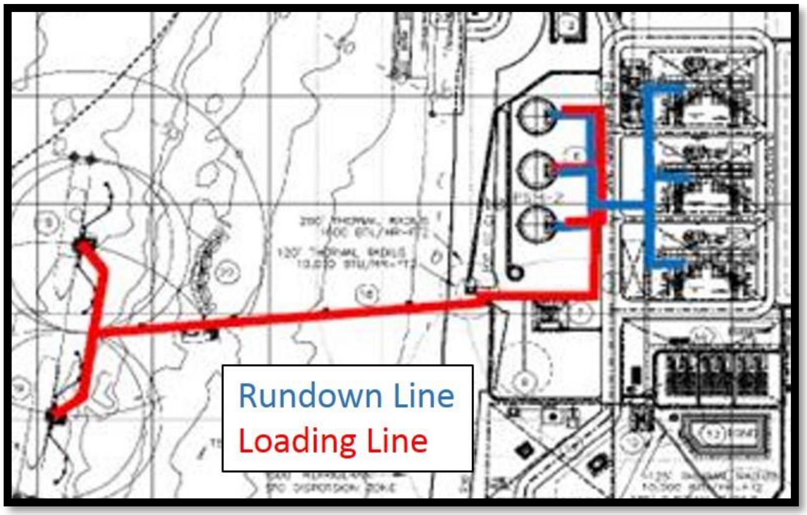

Figure 1: Typical marine LNG facility

A hypothetical SALS scenario for a 24" LNG rundown line with a length of 3,000 ft is shown on Figure 2. The SALS table would show a hole size of 8" (1/3 of the diameter), and the predicted ½ LFL flammable gas cloud may extend for 4,000+ ft, depending on the process conditions and leak duration.

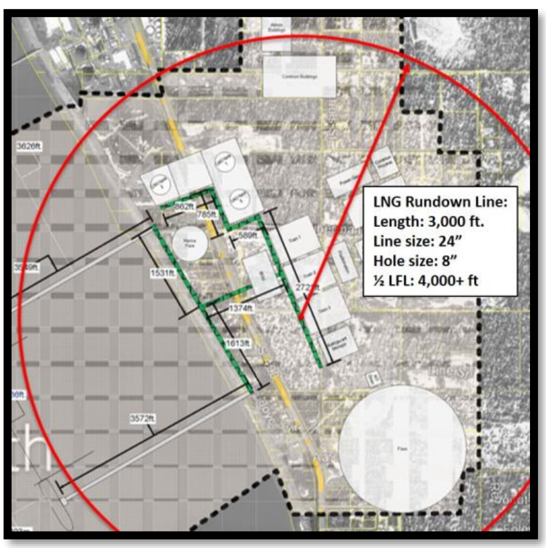

Figure 2: Hypothetical SALS for LNG Loading Line

In cases like this, the facility foot print would have to extend beyond the predicted ½ LFL gas cloud contour unless mitigations (typically "Vapor Barriers") are provided. Vapor barriers are commonly used to contain the release of flammable mixtures in LNG facilities in the United States [4]. Vapor barriers could be added along the marine jetty (see Figure 3), internally at the facility, or at the property line (see Figure 4). Dispersion modelling using CFD (computational fluid dynamics) software is required to identify the locations requiring vapor barriers, and also to demonstrate their effectiveness to the regulatory agencies.

Other vapor cloud mitigation alternatives are:

- Spacing.
- Engineering design (e.g. multiple smaller pipes).

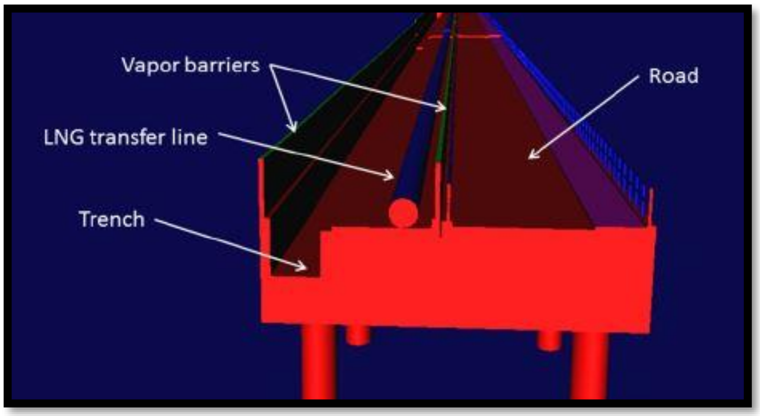

Figure 3: Vapor Barrier on Marine Jetty

(Figure courtesy of GexCon US / Figure extracted from FERC e-library document "Downeast LNG Project – Revised Vapor Dispersion Modelling at http://elibrary.ferc.gov/idmws/Doc_Family.asp?document_id=14117516 **) [6]**

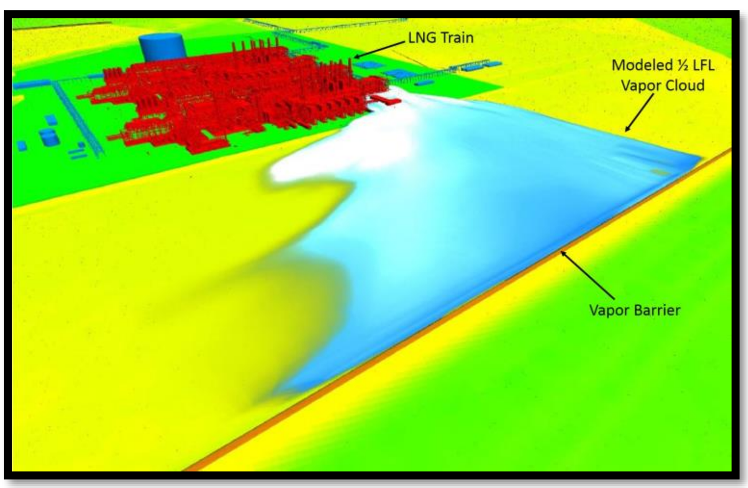

Figure 4: Vapor Barriers on Facility Property Line
(Figure courtesy of GexCon US)

3. Potential Disadvantages of Vapor Barriers

While it is acceptable by the regulators and applied successfully as a solution to force the predicted flammable gas clouds to stay within the limits required by the regulations, vapor barriers also present some potential disadvantages:

- In the event of a release, the gas cloud will be developed inside the vapor barrier limits, potentially increasing the escalation risk.
- Obstructions to physical access and visual inspection of the piping (e.g., vapor barriers along a marine jetty).
- Maintenance on vapor barriers required over the lifetime of the facility.
- Vapor barriers are designed to withstand the predicted winds at the facility location and may be large structures.

4. Alternative Solution for Vapor Cloud Reduction

An alternative solution for complying with the flammable gas exclusion zone regulations without the provision of vapor barriers is the application of Pipe-in-Pipe technology for long and large diameter LNG lines, typically the rundown and loading lines.
The Pipe-in-Pipe system consists on an inner pipe designed for the process conditions of a particular service, with insulation material located in the continuous annular space between the inner and outer pipe. The outer pipe is designed to provide full containment in the event of a leak from the inner pipe and to withstand any thermal deformation due to exposure to cryogenic temperatures. All welded construction is used for both the inner and the outer pipe. The specific piping materials for the inner pipe in the outer pipe on a Pipe-in-Pipe system is outside of the scope of this paper. See Figure 5 for a view of a typical Pipe-in-Pipe.

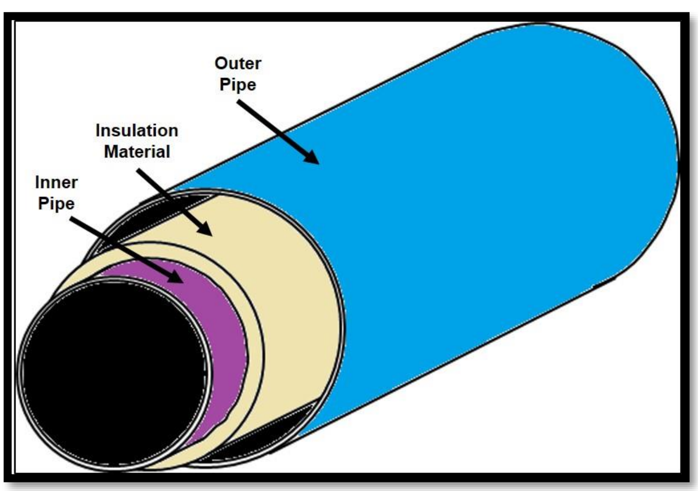

Figure 5: Typical Pipe-in-Pipe Cross Section

Since the main feature of the Pipe-in-Pipe technology for the LNG loading line and rundown line is to have any potential leaks from the inner pipe contained by the outer pipe, the probability of a simultaneous failure on the inner and outer pipe is extremely low, as covered in detail in the next section.

If a leak occurs in the inner pipe, it will be detected by continuous monitoring of the annular space, which can be achieved by temperature measurement via fiber optics for the length of the pipe, pressure monitoring, and/or gas composition monitoring. Any leakage can be directed to a safe disposition, such as a flare system.

5. Failure Rate for Conventional Pipe and Pipe-in-Pipe

DOT PHMSA (Department of Transportation Pipeline and Hazardous Materials Safety Administration) defines the hole sizes for the SALSs as the calculated failure rate based on pipe diameter and length, using the PHMSA provided Nominal Failure Rate Table, compared with the failure rate criterion of 3×10^{-5} failures per year [3].

The tables below show the credible SALS hole sizes for a hypothetical LNG pipe of 20" diameter and 3,000 ft length for two configurations:

- Conventional pipe (See Table 1 for failure rate calculation details).
- Pipe-in-Pipe system – 20" inner pipe / 24" outer pipe (See Table 2 for failure rate calculation details).

The PHMSA Nominal Failure Rate Table does not directly address Pipe-in-Pipe, therefore we calculated the SALS based on the failure rate for a simultaneous failure of the inner pipe and the outer pipe, applying PHMSA published failure rates [3].

Type of Failure	Failures per year of operation (conventional)	Failures per year of operation Total Pipe length: 3,000 ft = 914 m	PHMSA failure rate criterion of 3x10-5 failures per year
Piping: 500mm (20-inch) ≤d < 1000mm (40-inch)			
Catastrophic rupture	2E-8 per meter of piping	1.83E-05	Not applicable
Release from hole with effective diameter of 1/3 diameter	1E-7 per meter of piping	9.14E-05	Applicable
Release from hole with effective diameter of 10% diameter, up to 50mm (2-inches)	2E-7 per meter of piping	1.83E-04	Applicable
Release from hole with effective diameter of 25mm (1-inch)	4E-7 per meter of piping	3.66E-04	Applicable

Table 1: Prescribed SALS Hole Sizes – 20" / 3,000 ft – Conventional Piping

As seen on results from Table 1, for a LNG line of 20" diameter and 3,000 ft length, if conventional piping is used, the dispersion analysis is required for a hole size of up to 1/3 of the diameter (6.7"), which most probably will generate a large ½ LFL flammable gas contour, requiring either a larger facility foot print or the adoption of vapor barriers to contain the potential gas cloud inside the facility limits.

Type of Failure	Failures per year of operation (inner pipe) Total Pipe length: 3,000 ft = 914 m	Failures per year of operation (outer pipe) Total Pipe length: 3,000 ft = 914 m	Failures per year of operation (PiP system) Total Pipe length: 3,000 ft = 914 m	PHMSA failure rate criterion of 3x10-5 failures per year
Piping: 500mm (20-inch) ≤d < 1000mm (40-inch)				
Catastrophic rupture	1.83E-05	1.83E-05	3.34E-10	Not applicable
Release from hole with effective diameter of 1/3 diameter	9.14E-05	9.14E-05	8.35E-09	Not applicable
Release from hole with effective diameter of 10% diameter, up to 50mm (2-inches)	1.83E-04	1.83E-04	3.34E-08	Not applicable
Release from hole with effective diameter of 25mm (1-inch)	3.66E-04	3.66E-04	1.34E-07	Not applicable

Table 2: Prescribed SALS Hole Sizes – 20” / 3,000 ft – Pipe-in-Pipe system

If a Pipe-in-Pipe system is used for this hypothetical LNG line, based on results from Table 2 for a simultaneous failure on both internal and external piping, the dispersion analysis for holes sizes as small as 1 inch is not applicable, since the calculated failure rate is smaller than PHMSA threshold of 3 x 10^{-5} failure per year, and that will allow the LNG facility to design a more compact overall property foot print.

An additional advantage of the Pipe-in-Pipe system is that the required liquid containment system along the LNG transfer lines will be fulfilled by the outer pipe, therefore no open trenches and sump system for secondary liquid containment will be necessary. These features make the Pipe-in-Pipe system an acceptable option with a better approach to process safety and provide less exposure for the public and plant personnel.

6. Regulatory Submissions

The use of the Pipe-in-Pipe system is currently not covered in the regulations that currently govern siting of LNG facilities (Title 49 of the Code of Federal Regulations (CFR) Part 193, *Liquefied Natural Gas Facilities: Federal Safety Standards* [1], and NFPA 59A – 2001 Edition, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas* [2].) The 2013 edition of NFPA 59A covers cryogenic Pipe-in-Pipe systems.

The use of this system in the design of proposed LNG plant projects in the United States will require regulatory review on a case-by-case basis and the demonstration of an equivalent or better level of safety compared with a conventional piping system. A special permit process with the applicable regulatory agencies may be required [3].

If approved by the regulatory agencies, the Pipe-in-Pipe technology will allow proposed LNG projects:

- Significant reduction of flammable gas clouds probability and size scenarios, potentially eliminating the need for vapor barriers.
- Enhanced secondary liquid containment system for the PiP sections, with no open trenches.
- An alternative approach to prevent incidents and potential escalation.

There is at least one proposed LNG facility design incorporating Pipe-in-Pipe currently under review by FERC and DOT PHMSA.

7. Conclusions

The Pipe-in-Pipe technology, presented in this paper, which consists of two concentric pipes on a full containment system, provides an alternative option to conventional piping for LNG transfer lines of large diameter and long extension. Pipe-in-Pipe allows proposed projects to design their facilities with a significant reduction on flammable gas clouds probability and size and enhanced process safety features for better protection of the public and plant personnel.

This technology has not yet been used for this application in previous LNG projects and would require prospective projects to pursue approval from the applicable regulatory agencies through a special permit or safety equivalency submission. This process is currently ongoing for at least one proposed LNG facility.

8. References

[1] *Title 49, Federal Code of Regulations, Part 193 – Liquefied Natural Gas Facilities: Federal Safety Standards.*

[2] NFPA (National Fire Protection Association) 59A - *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG), 2001 Edition.*

[3] PHMSA FAQ, *http://primis.phmsa.dot.gov/lng/faqs.htm*

[4] B. Hendrickson, C. Marsegan, F. Gavelli, "Where to Begin –A Parametric Study for Vapor Barriers at LNG Export Facilities", in *Mary Kay O'Connor Process Safety Symposium*, 2015.

[5] FERC LNG, *http://www.ferc.gov/industries/gas/indus-act/lng.asp*.

[6] FERC e-library, project file 14117516, "Downeast LNG Project – Revised Vapor Dispersion Modelling", *http://elibrary.ferc.gov/idmws/Doc_Family.asp?document_id=14117516*