Oregon Department of Environmental Quality

Seismic Vulnerability Assessment Forms

Form 5: LNG Tanks and Pipelines

1. Submit a plan view of the LNG tank farm, to scale, including cross-sections/dimensions of all dikes. **(LNG1)**
2. For each LNG tank, provide tank age, any previous inspection records, dimensions (height or diameter) and type of anchorage. If a tank is empty, provide details of how long since usage and whether or not it is permanently out of service. From the results of the geotechnical investigations or reports verify the site class (A-F) with the appropriate seismic risk. For the parallel treatment of the tanks compared to the DEQ requirement of Risk Classification IV (Per DEQ340-300-0004(a)(a) and Table 1.5.1, ASCE7), the analogous treatment for tanks would be the "SUGIII" classification. **(LNG2).**
3. Verify dike capacities are within allowable spill volumes, as stated in 40 CFR 264.175(b). "Spill Prevention, Control and Countermeasure Requirements" and that the secondary containment is sufficient to contain the entire contents of the largest tank. Containment (40 CFR193.2181) must include 110% of the maximum capacity of one LNG tank, or 100% of all tanks (whichever is larger; other option is V = 100% of impound considering dynamic surge in the event of a container failure, or V = 100% where the height of the impound is equal to or greater than the maximum liquid level in the tank (NFPA 59A, Section 5.3.2.1). (**LNG3)**
4. Verify that the dike is consistent with Section 5.3.2.10 and Figure 5.3.2.10 (NFPA 59A). Dike must be concrete (49 CFR 193.2161) **(LNG4).**
5. Per 49CFR193.2155, 2173, the structural impound system (dikes) must be designed and constructed such that it can facilitate **(LNG5):**

a. Full hydrostatic head of impounded LNG,

b. Hydrodynamic loads,

c. Any jet discharged at any predicted angle, and

d. The effect of temperature on the impound system

e. The water removal system must be adequate to remove water at 25% of maximum predicted rate from a 10-year return period storm and 1-hour duration.

6. The first and preliminary inspection or assessment of the tank farm consists of a walk-through based on CalARP, with the seismic evaluations performed under the direction of an Oregon registered civil, structural, or mechanical engineer (CalARP Section 1.4). This includes a preliminary seismic assessment, using the demand as provided in the initial geotechnical inspection/report required by the DEQ. This preliminary assessment would include possible liquefaction or lateral spreading, seismic settlement, and landslides (per CalARP Sections 2.3, 2.4 and 2.5). This initial report provides some direction for the LNG tank assessment per 40 CFR 293 and NFPA 59A. **(LNG6)**

The following set of checklist questions is taken from NFPA 59A, "Standard for the Production, Storage, and Handling of LNG 2013 edition" unless noted.

7. The seismic ground motion must be determined with a site-specific investigation (NFPA 59A, 7.4.4.1, ASCE7 Chapter 21). If there is no record for the vertical spectra shall be 2/3 of the horizontal. Per NFPA 59A, Annex B, the seismic design must include the SSE and the ALE. The SSE is based on the 2% Probability of exceedance in 50 years. The LNG tank must not have a catastrophic failure during this event. An alternative method to determine seismic criteria is in API

625 and 620 (Appendix L). ASCE 7 would require compliance with 2/3 of the MCE, with an importance factor of 1.5, so using the full DE (or SSE 2% with the 50-year return period) is consistent with the ASCE7 MCE factored down,

and then with the importance factor of 1.5. (NFPA 59A, Annex B). It does not require to be operational post-SSE. The ALE is ½ of the SSE and from Annex B, the ALE event requires the containment volume of the entire tank to remain intact within the dike. Describe the methodology and resulting OBE, SSE and ALE for the LNG tank used for the analysis/design of the tank and anchorage. Explain compliance with DEQ 340-300-0003 (1)(f) using the ASCE7 Design Level Earthquake (or CLE per 49 CFR 193) to evaluate the potential for a spill larger than the MAUS of 1 bbl. Per CSA Z276, Section 7.1.5 the seismic assessment is to include a PSHA (Probabilistic Seismic Hazard Assessment) is required per this Canadian reference, but in their situation, the Cascadia subduction zone is not considered; per DEQ 340-300-0001(a) it is to be included. Per API 650, the seismic risk group would be SUG III (API 650, Annex E, Section E.3.1.1). With this seismic criterion, tank spills are limited to the MAUS (1 bbl./ tank). Verify site classification and associated PGA/Spectra and how obtained. **(LNG7)**

8. Verify containment of dike or impound wall per NFPA 59A 5.3.2.10 and Figure 5.3.2.10. Verify water removal per Section 5.3.2.11.2. **(LNG8)**
9. Verify compliance with the design spill Table 5.3.3.7, and that automatic valves for flow into the LNG tank have an automatic fail-safe valve or has two back-flow check valves. **(LNG9)**
10. Verify all process equipment is located at least 50 ft. from ignition sources, an adjacent property line that can be built on, offices, stores, and occupied bldgs. (5.3.6.1). **(LNG10)**
11. Buildings associated with the LNG processes should be considered category IV per ASCE7, and the DE earthquake (Classification I) (NFPA 59A, Section 5.4.2.1). Buildings with enclosed LNG shall meet the requirements of 5.4.5. **(LNG11)**
12. The LNG tank shall meet the requirements of API 625 and comply with API 620 (Section 7.2) **(LNG12)**
13. All penetrations into the tank shall have them marked with their functions (7.3.4.3). **(LNG13)**
14. If there are any shop-built LNG tanks, they must comply with the seismic design per NFPA 59A, 7.5.2 **(LNG14)**
15. Per NFPA 59A, 7.5.2.4 – seismic instrumentation is required – free field **(LNG15).**
16. Per NFPA 59A Section 13.18.4.2 regarding the maintenance manual:
    a. Each facility operator shall prepare a written manual that sets out an inspection and maintenance program for identified components that are used in the facility.
    b. The maintenance manual for facility components shall include the following:
        i. The manner of carrying out and the frequency of the inspections and tests referred to in 13.18.4.1
        ii. A description of any other action in addition to those referred to in 13.18.4.2(B)(1) that is necessary to maintain the facility in accordance with this standard
        iii. All procedures to be followed during repairs on a component that is operating while it is being repaired, to ensure the safety of persons and property at the facility
    c. Each facility operator shall conduct the facility's maintenance program in accordance with the written manual for facility components.
    d. The external surfaces of LNG storage tanks shall be inspected and tested as set out in the maintenance manual for the following:
        i. Inner tank leakage
        ii. Soundness of insulation
        iii. Tank foundation heating to ensure that the structural integrity or safety of the

tanks is not affectedPer Section 13.18.4.6 Maintenance Records **- (A)** Each facility operator shall maintain a record of the date and the type of each maintenance activity performed. **(B)** Maintenance records shall be retained for a period of not less than 5 years.

e. Per Section 14.8.12.2 If a potentially damaging geophysical or meteorological event occurs, the following shall be accomplished: The plant shall be shut down as soon as is practical. The LNG tank must be inspected/tested to verify the foundation and tank movement after a major earthquake – check for inner tank leakage, effectiveness of insulation and frost heave. (49 CFR 193.2623). **(LNG16)**

17. Inspection of the foundation (NFPA 59A, Section 14.8.3) – The support system/foundation of each component shall be inspected at least annually. If the support/foundation is incapable of supporting the component, it shall be repaired **(LNG17)**
18. Regarding emergency power (NFPA 59A, Section 14.8.4) – Monthly, and annual testing of the emergency power shall also be conducted. Control systems must have at least two sources of power; fuel supplies must be protected from hazards (49CFR 193.2445). **(LNG18)**
19. Corrosion control (NFPA 59A, Section 14.8) – The facility must have protection from corrosion, inspection/repair is part of scheduled maintenance (Section 14.3). Electrical interference from other electrical currents is protected. Buried components that are cathodically protected shall be surveyed at least once a year or not to exceed 15 months. Each cathodic rectifier/impressed current system shall be inspected at least 6 times/calendar year. Each component subject to corrosion from the atmosphere shall be inspected at intervals not to exceed 3 years. Internal corrosion monitoring devices shall be checked at least twice a year. If inspection shows that corrosion is not being controlled at the LNG facility, necessary actions shall be taken. **(LNG 19)**.

The following questions are from the Federal Code of Regulations, 49 CFR 193 "LNG facilities: Federal Safety Standards" unless noted.

20. Each operator must maintain all plans/procedures and must be available to any state agency that has a certification/agreement with the plant. These are to be updated at least once every 2 years or whenever a new component is installed. (193.2017a). Records of components, buildings, foundations, and support systems must be maintained for the life of the project (193.2119) **(LNG20)**.
21. The following facilities must be surrounded by protective enclosures: storage tanks, impound systems, vapor barriers, cargo transfer systems, control rooms/stations, control systems, fire control equipment, alternative power sources and security communication systems (193.2905) **(LNG21)**.
22. Operator must maintain plans and procedures for the facility, and any changes to the plans or operations must be available for review/inspection within 20 days after the change was made (193.2017**) (LNG22).**

LNG pipelines tank requirements and systems

23. Provide current P&IDs of each LNG and other pipelines (e.g. fire water). If any are buried or raised, provide details and cryosections (burial depth, etc.) (**LNG23**).
24. All LNG piping must comply with all of Chapter 7 of NFPA 59A and the requirements in API 625. All piping systems shall be designed in accordance with ASME B31.3, 2006 Edition, except pipelines for use in low temperature or cryogenic service shall be furnished in accordance with ASME B31.3, Paragraph 323.2.2A and Table A-1. **(LNG24).**
25. All LNG tank systems should have both top and bottom filling, unless other methods are used to prevent stratification (NFPA 59A, 7.3.1.3) **(LNG25).**
26. Verify that all exposed insulation is noncombustible, is a vapor barrier, water-free and cannot be

moved by fire water hose streams. (NFPA 59A, 7.3.3) **(LNG26).**

27. Provide for each pipeline: age, inspection history (internal and external) **(LNG27).**
28. If any pipelines are insulated, describe, and provide inspection history**. (LNG28).**
29. Provide all pipeline stress analyses and dates **(LNG29).**
30. Process piping must be within the scope of ASME B31.3. Verify that all piping LNG up to the emergency shutdown valves/firewater piping is Category 1, designed for the OBE and SSE, using the 9.2.2.2 section of NFPA 59A**. (LNG30).**
31. Verify that LNG piping can accommodate fatigue from thermal cycling, (NFPA 59A, Section 9.2.3) **(LNG31).**
32. Verify that the threaded pipe is at least Schedule 80 (NFPA 59A, 9.3.2.4**) (LNG32).**
33. LNG valves must comply with NFPA 59A Section 9.3.4.1 (ASME B31.3). Valves for emergency shut-off larger than 8 inches must be powered or have manual operations (NFPA 59A, 9.4.2.8**) (LNG33).**
34. Records of all leak tests shall conform to paragraph 345.27 of ASME B 31.3 – records are to be kept for the life of the piping system. **(LNG34).**
35. For instrumentation and electrical services, the facility must comply with Chapter 10, and Table 10.7.2 and Figure 10.7 of NFPA 59A. **(LNG35).**
36. Hoses for LNG and refrigerant transfer shall be tested at least annually to the maximum pump pressure or relief valve setting and shall be inspected visually before each use for damage or defects. Transfer hoses must be tested once a year, and visually inspected before each use (49 CFR 193.2621) **(LNG36).**
37. LNG Pipe Markings – Per NFPA 59A, Section 9.4, markings on pipe shall comply with the following:

    (LNG37)

    a. Markings shall be made with a material compatible with the pipe material. Materials less than

    1⁄4 in. (6.4 mm) in thickness shall not be die stamped.

    b. Marking materials that are corrosive to the pipe material shall not be used.

    c. Piping shall be identified by color coding, painting, or labeling.
38. Per Section 9.5, NFPA59A**,** pipe supports, including any insulation systems used to support pipe whose stability is essential to plant safety, shall be resistant to or protected against fire exposure, escaping cold liquid, or both, if they are subject to such exposure. Per Section 9.5.2 pipe supports for cold lines shall be designed to minimize heat transfer, which can result in piping failure by ice formations or embrittlement of supporting steel. Per Section 9.5.3, the design of supporting elements shall conform to ASME B 31.3, Section 321 **(LNG38).**
39. Per section 9.7, NFPA 59A 9.7 Inspection, Examination, and Testing of Piping. Inspection, examination, and testing shall be performed in accordance with Chapter VI of ASME B 31.3 to demonstrate sound construction, installation and leak tightness. Unless specified otherwise in the engineering design, piping systems for flammable liquids and flammable gases shall be examined and tested per the requirements of ASME B 31.3, Normal Fluid Service. Per Section 9.7.1.1, leak testing shall be conducted in accordance with ASME B 31.3, Section 345 **(LNG39).**
40. LNG Valves (NFPA 59A, Section 14.8.10) - Stationary LNG tank relief valves shall be inspected and set-point tested at least once every two calendar years, with intervals not exceeding 30 months, to ensure that each valve relieves at the proper setting. All other relief valves protecting hazardous fluid components shall be randomly inspected and set-point tested at intervals not exceeding five years plus three months. Stop valves for isolating pressure or vacuum-relief valves shall be locked or sealed open. Cryogenic valves in liquid cryogenic service shall not be installed in vertical lines; these valves shall be installed in horizontal lines with the stem in the vertical. Shutoff valves shall be located inside the impoundment area as close as practical to such containers, tanks, and vessels

where provided. Per NFPA 59A section 14.8.10.10 an LNG container shall have no more than one stop valve closed at one time. When a component is served by a single safety device and the safety device is taken out of service for maintenance or repair, the component shall also be taken out of service, unless safety is accomplished by an alternative means. All of the LNG piping systems and valves shall conform to Chapter 9, NFPA 59A. Verify that hoses for LNG transfer are tested at least annually to the maximum pump pressure or relief valve setting, and are inspected visually before each use (NFPA 59A, Section 14.8.6) **(LNG40)**

41. Piping flexibility – Per Appendix “L” of API 620, Section L.4.2.9 piping, supports, foundations and superstructures supporting piping attached to the tank shall be designed for the piping displacements

(See Table E-8, API 650 Appendix E) with a 33% increase in stress). With the 2% in 50-year CE criteria, an importance factor of 1.0 is used**. (LNG41).**

42. Verify that the electrical classifications of the facility are consistent with Table 10.7.2 and Figures 10.7.2 (a) (b) (c) (d) of NFPA 59A. **(LNG42).**

References

1. National Fire Protection Association. 2013. “NFPA 59A Standard for Production, Storage and Handling of LNG.” NFPA publications, Quincy, MA.
2. American Petroleum Institute. 2021. “API Standard 620, 12th edition: Design and Construction of Large, Welded, Low Pressure Storage Tanks.” API publications, Washington, D.C.
3. Liquid Natural Gas Facilities, Federal Safety Standards of 2022 § 49 CFR § 193
4. Canadian Standards Association. 2022. LNG Production, Storage and Handling Z276:22, Toronto, CA: CSA Group.

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