FERC Reporting Requirements and Lagging and Leading Indicators

October 31, 2023

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Federal Energy Regulatory Commission

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Outline

- LNG Regulatory Authorities and Jurisdiction
- FERC LNG Engineering Reviews and Requirements
- FERC Incident Notification, Semi Annual Report, and Operational Inspection Requirements
- Leading and Lagging Indicators (API 754 etc.)
- Lessons learned from Semi Annual Report and Incident Notification Requirements based on EPA LDAR Requirements

Who Regulates LNG?

Natural Gas Act (NGA) and National Environmental Policy Act (NEPA)

3 NATURAL GAS ACT

EXPORTATION OR I[...]

SEC. 3. (a) Afte[...] takes effect no perso[...] States to a foreign [...] eign country withou[...] sion authorizing it t[...] upon application, un[...] the proposed export[...] the public interest. [...] application, in whol[...] such terms and con[...] or appropriate, and [...] hearing, and for goo[...] in the premises as it [...]

sion authorizing it to do so. The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest. The Commission may by its order grant such application, in whole or in part, with such modification and upon such terms and conditions as the Commission may find necessary or appropriate, and may from time to time, after opportunity for hearing, and for good cause shown, make such supplemental order in the premises as it may find necessary or appropriate.

(b) With respec[...] United States from a nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas, and with respect[...]

(1) the impo[...] a "first sale" wit[...] Gas Policy Act o[...]

(2) the Com[...] gin, treat any su[...] sonable, unduly [...]

(c) For purposes [...] ural gas referred to [...] gas to a nation with [...] requiring national t[...] deemed to be consist[...] for such importation [...] fication or delay.

(d) Except as sp[...] Act affects the rights [...]

(1) the Coas[...] 1451 et seq.);

(2) the Clea[...]

(3) the Fed[...] 1251 et seq.).

(e)(1) The Commission shall have the exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal. Except as specifically provided in this Act, nothing in this Act is intended to affect otherwise applicable law related to any Federal agency's authorities or responsibilities related to LNG terminals.

(2) Upon the filing of any application to site, construct, expand, or operate an LNG terminal, the Commission shall—

(A) set the matter for hearing;

(B) give reasonable notice of the hearing to all interested persons, including the State commission of the State in which the LNG terminal is located and, if not the same, the Governor-appointed State agency described in section 3A;

(C) decide the matter in accordance with this subsection; and

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functions, [...] as trustee [...] productive, [...] the envi- [...] y, or other [...] ng and a wide sharing

(6) enhance the quality of renewable resources and approach the maximum attainable recycling of depletable re-

[...]ch person should enjoy a [...]son has a responsibility to [...]ancement of the environ-

[...]d directs that, to the full- [...]ations, and public laws of [...]d administered in accord- [...]ct, and (2) all agencies of

[...]ciplinary approach which [...]natural and social sciences [...] planning and in decision- [...] man's environment; [...]s and procedures, in con- [...]ronmental Quality estab- [...]will insure that presently [...]ies and values may be [...]ecisionmaking along with [...];

[...]dation or report on pro- [...]r Federal actions signifi- [...]uman environment, a de- [...]ficial on— [...] of the proposed action,

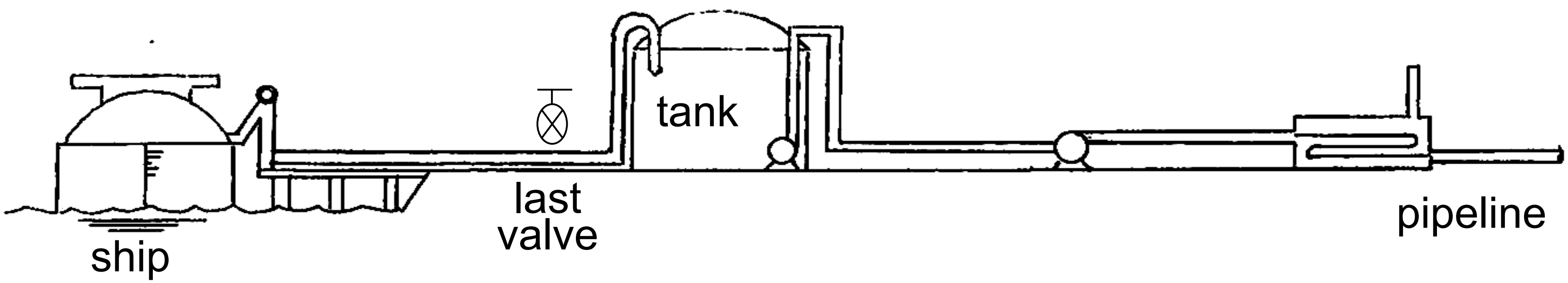
(ii) any adverse environmental effects which cannot be avoided should the proposal be implemented,

(iii) alternatives to the proposed action,

(iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and

(v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

Federal Safety/Security Jurisdiction – Most Common Example

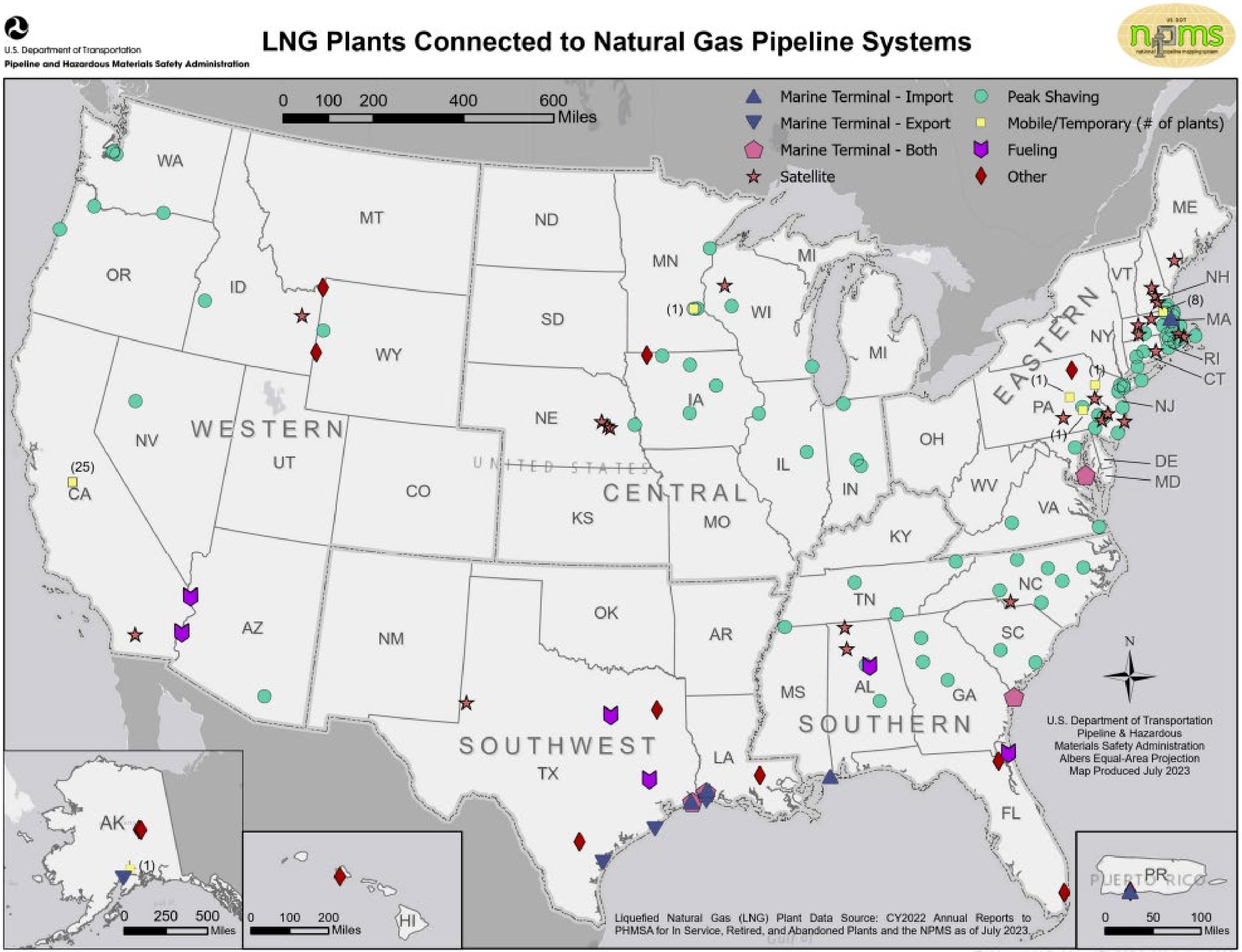


FERC – 18 CFR 380, 40 CFR 1500-1508 (Lead Agency for NEPA)			
	FERC – 18 CFR 153 (Application under NGA)		Sec 3/7
	DOT – 49 CFR 193 (Subpart B - Siting)		Sec 3/7
46 CFR 154	USCG – 33 CFR 127	DOT – 49 CFR 193 (Subparts C to I)	192
33 CFR 104 (Vessel Security)	USCG – 33 CFR 105 Facility Security		TSA

Who Regulates LNG?

LNG Facility (does not include pipeline)	DOE	FERC	DOT	MARAD	USCG	BSEE	EPA RMP	OSHA PSM
Import/Export Terminals (Onshore)	✓	✓	✓		✓		✓	✓
Import/Export Terminals (Near-shore)	✓	✓			✓		✓	✓
Import/Export Terminals (Offshore)	✓			✓	✓	✓		
Interstate LNG Facilities (Peak shaving)		✓	✓					
Intrastate LNG Facilities (Peak Shaving, Satellite)			✓					
Vehicular Use (Vessel, Barges, Truck, Rail)			✓		✓			

DOT PHMSA Jurisdictional LNG Facilities



https://www.npms.phmsa.dot.gov/Documents/LNG_AR_National.pdf

FERC Jurisdictional LNG Facilities - Summary

As of end of **2021**:

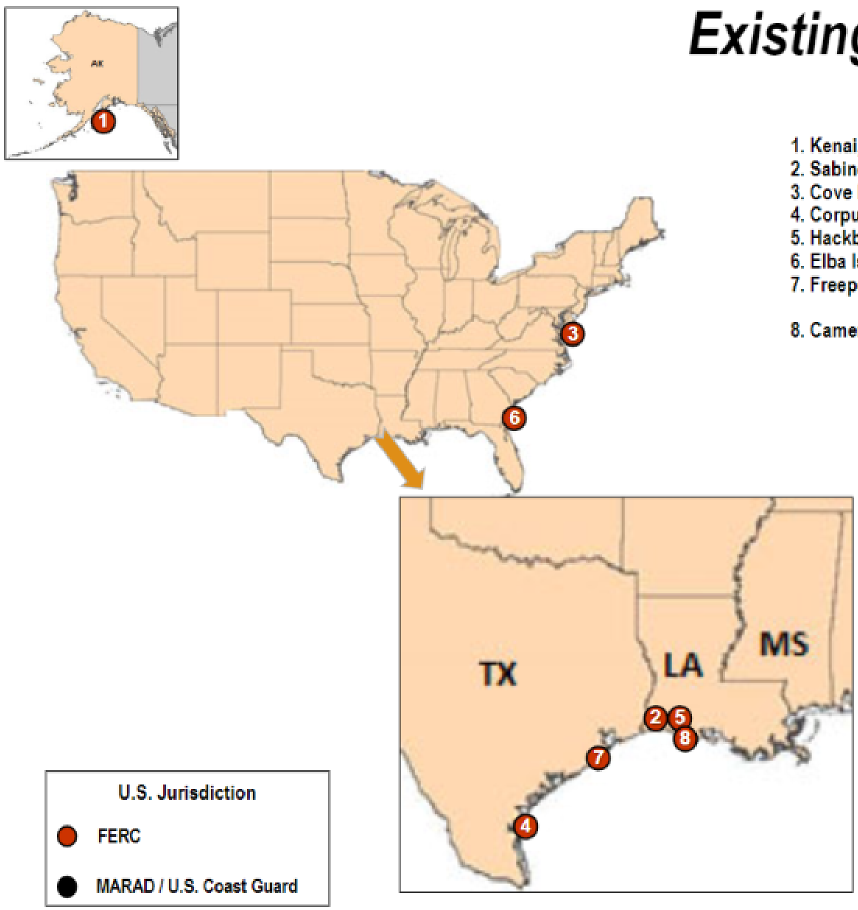
- 26 of 168 (**15%**) of in-service DOT PHMSA **LNG facilities** are jurisdictional to FERC:
  - By type: 13 of 26 (**50%**) of **baseload LNG plants**, 13 of 70 (**19%**) of **LNG peakshaving plants**, 0 of 57 (0%) of satellite LNG plants, 0 of 40 (0%) of mobile LNG plants, and 0 of 9 (0%) of other LNG plants.
  - By function: 13 of 13 (**100%**) of **LNG marine terminals**, 13 of 102 (**13%**) of **LNG storage plants**, 0 of 3 stranded, 0 of 6 vehicular, and 0 of 44 other LNG plants.
- 12.1 Billion cubic feed per day (Bcfd) of 12.4 Bcfd (**97%**) of **liquefaction capacity** are jurisdictional to FERC
- 64 of 242 (26%) of LNG containers, but approximately 150 Billion cubic feet (Bcf) of 210 Bcf (**72%**) of **storage capacity** are jurisdictional to FERC
- 163 of 441 LNG vaporizers (37%), but 20.0 of 28.3 Bcfd (**71%**) of **vaporization capacity** are jurisdictional to FERC

FERC Jurisdictional LNG Facilities - Existing

United States LNG Export Terminals

Existing

1. **Kenai, AK:** 0.2 Bcfd (Trans-Foreland)
2. **Sabine, LA:** 4.55 Bcfd (Cheniere/Sabine Pass LNG – Trains 1-6)
3. **Cove Point, MD:** 0.79 Bcfd (Dominion–Cove Point LNG)
4. **Corpus Christi, TX:** 2.40 Bcfd (Cheniere – Corpus Christi LNG Trains 1-3)
5. **Hackberry, LA:** 2.06 Bcfd (Sempra–Cameron LNG, Trains 1-3)
6. **Elba Island, GA:** 0.35 Bcd (Southern LNG Company Units 1-10)
7. **Freeport, TX:** 2.38 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction Trains 1-3)
8. **Cameron Parish, LA:** 1.11 Bcfd (Venture Global Calcasieu Pass Units 1-6)

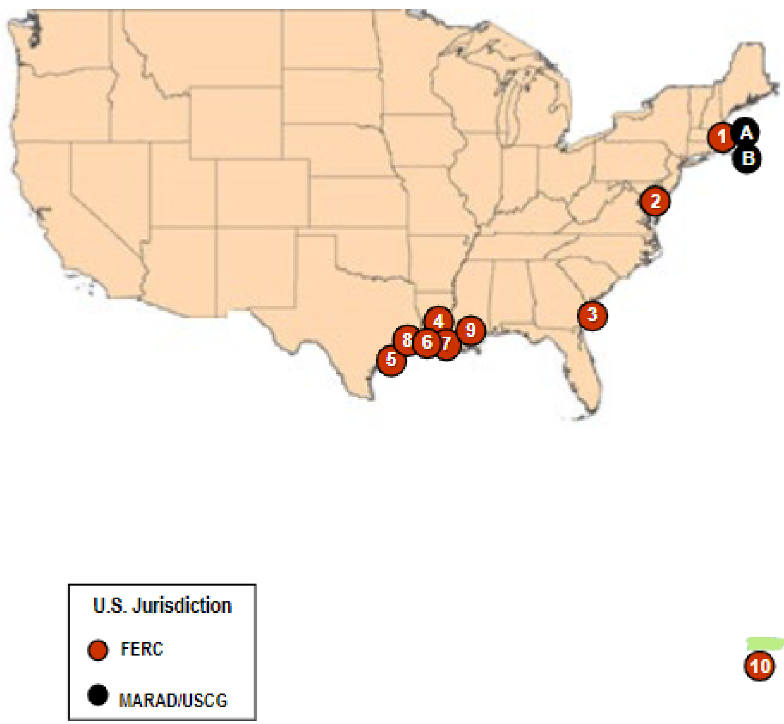


As of October 10, 2023
No updates since previous issuance

https://www.ferc.gov/natural-gas/lng

FERC Jurisdictional LNG Facilities - Existing

United States LNG Import Terminals
Existing



FERC Jurisdiction

1. **Everett, MA:** 1.035 Bcfd (GDF SUEZ - DOMAC)
2. **Cove Point, MD:** 1.8 Bcfd (Dominion - Cove Point LNG) ★
3. **Elba Island, GA:** 1.6 Bcfd (El Paso - Southern LNG) ★
4. **Lake Charles, LA:** 2.1 Bcfd (Southern Union – Lake Charles LNG) ★
5. **Freeport, TX:** 1.5 Bcfd (Cheniere/Freeport LNG Dev.) ★★
6. **Sabine, LA:** 4.0 Bcfd (Cheniere/Sabine Pass LNG) ★★
7. **Hackberry, LA:** 1.8 Bcfd (Sempra - Cameron LNG) ★
8. **Sabine Pass, TX:** 2.0 Bcfd (ExxonMobil – Golden Pass) (Phase I & II)
9. **Pascagoula, MS:** 1.5 Bcfd (El Paso/Crest/Sonangol - Gulf LNG Energy)
10. **Peñuelas, PR:** 0.3 Bcfd (EcoElectrica)

MARAD/USCG

A. **Offshore MA:** 0.8 Bcfd (Excelerate Energy – Northeast Gateway)
B. **Offshore MA:** 0.4 Bcfd (GDF SUEZ – Neptune LNG)

★ Authorized to re-export delivered LNG
★ Added liquefaction and export capabilities (also shown on the LNG Export Terminals Existing map)

As of September 26, 2023
No updates since previous issuance

https://www.ferc.gov/natural-gas/lng

FERC Jurisdictional LNG Facilities - Existing

FERC Jurisdictional Peakshavers

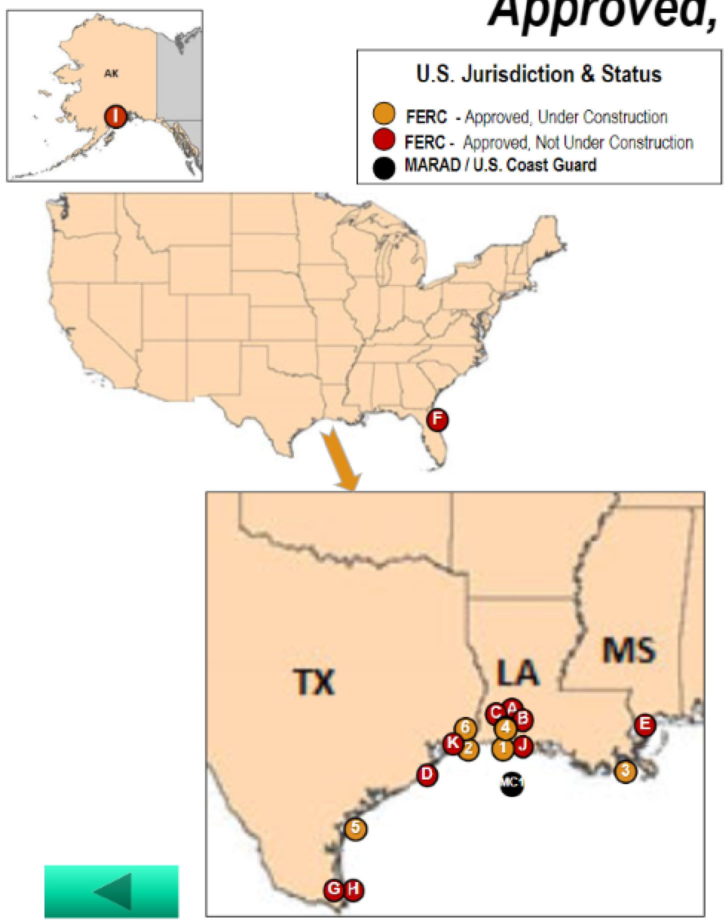
1. **Chattanooga Gas Co.**, Chattanooga, TN
2. **Columbia Gas Transmission, Inc.**, Chesapeake, VA
3. **East Tennessee Natural Gas, L.L.C.**, Kingsport, TN
4. **Hopkinton LNG Corp.**, Hopkinton, MA
5. **National Grid LNG, L.P.**, Providence, RI
6. **Northern Natural Gas Co.**, Garner, IA
7. **Northern Natural Gas Co.**, Wrenshall, MN
8. **Northwest Pipeline Corp.**, Plymouth, WA
9. **Pine Needle LNG Co.**, Stokesdale, NC
10. **Paiute Pipeline Co.**, Lovelock, NV
11. **Total Peaking Services, L.L.C.**, Milford, CT
12. **Transcontinental Gas Pipe Line Co., L.L.C.**, Carlstadt, NJ
13. **UGI LNG, Inc.**, Reading, PA

As of October 3, 2023
No updates since previous issuance

https://www.ferc.gov/natural-gas/lng

FERC Jurisdictional LNG Facilities - Approved

United States LNG Export Terminals
Approved, Not Yet Built



FERC – APPROVED, UNDER CONSTRUCTION

1. **Cameron Parish, LA:** 0.61 Bcfd (Venture Global Calcasieu Pass Units 7-9) (CP15-550)
2. **Sabine Pass, TX:** 2.57 Bcfd (ExxonMobil – Golden Pass) (CP14-517, CP20-459)
3. **Plaquemines Parish, LA:** 3.32 Bcfd (Venture Global Plaquemines) (CP17-66)
4. **Calcasieu Parish, LA:** 3.81 Bcfd (Driftwood LNG) (CP17-117)
5. **Corpus Christi, TX:** 1.58 Bcfd (Cheniere Corpus Christi Stage III) (CP18-512)
6. **Port Arthur, TX:** 1.86 Bcfd (Sempra - Port Arthur LNG Trains 1 & 2) (CP17-20)

FERC – APPROVED, NOT UNDER CONSTRUCTION

A. **Lake Charles, LA:** 2.27 Bcfd (Lake Charles LNG) (CP14-120)
B. **Lake Charles, LA:** 1.22 Bcfd (Magnolia LNG) (CP14-347)
C. **Hackberry, LA:** 0.93 Bcfd (Sempra - Cameron LNG Train 4) (CP15-560, CP22-41)
D. **Freeport, TX:** 0.74 Bcfd (Freeport LNG Dev Train 4) (CP17-470)
E. **Pascagoula, MS:** 1.50 Bcfd (Gulf LNG Liquefaction) (CP15-521)
F. **Jacksonville, FL:** 0.13 Bcf/d (Eagle LNG Partners) (CP17-41)
G. **Brownsville, TX:** 0.62 Bcfd (Texas LNG Brownsville) (CP16-116)
H. **Brownsville, TX:** 3.73 Bcfd (Rio Grande LNG – NextDecade) (CP16-454)
I. **Nikiski, AK:** 2.76 Bcfd (Alaska Gasline) (CP17-178)
J. **Cameron Parish, LA:** 1.21 Bcfd (Commonwealth LNG) (CP19-502)
K. **Port Arthur, TX:** 1.86 Bcfd (Sempra - Port Arthur LNG Trains 3 & 4) (CP20-55)

MARAD/USCG – APPROVED, NOT UNDER CONSTRUCTION

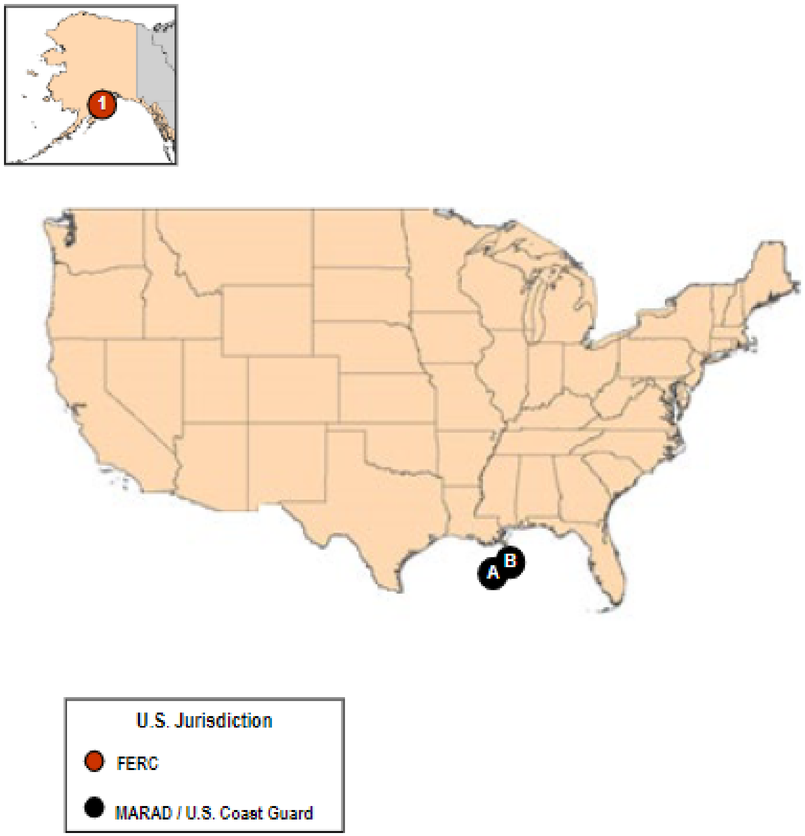
MC1. Gulf of Mexico: 1.8 Bcfd (Delfin LNG)

As of October 10, 2023
No updates since previous issuance

https://www.ferc.gov/natural-gas/lng

FERC Jurisdictional LNG Facilities - Approved

United States LNG Import Terminals
Approved, Not Yet Built



APPROVED - UNDER CONSTRUCTION - FERC
None

APPROVED – NOT UNDER CONSTRUCTION – FERC
1. **Kenai, AK:** .007 Bcfd (Trans-Foreland – Kenai LNG) (CP15-521)

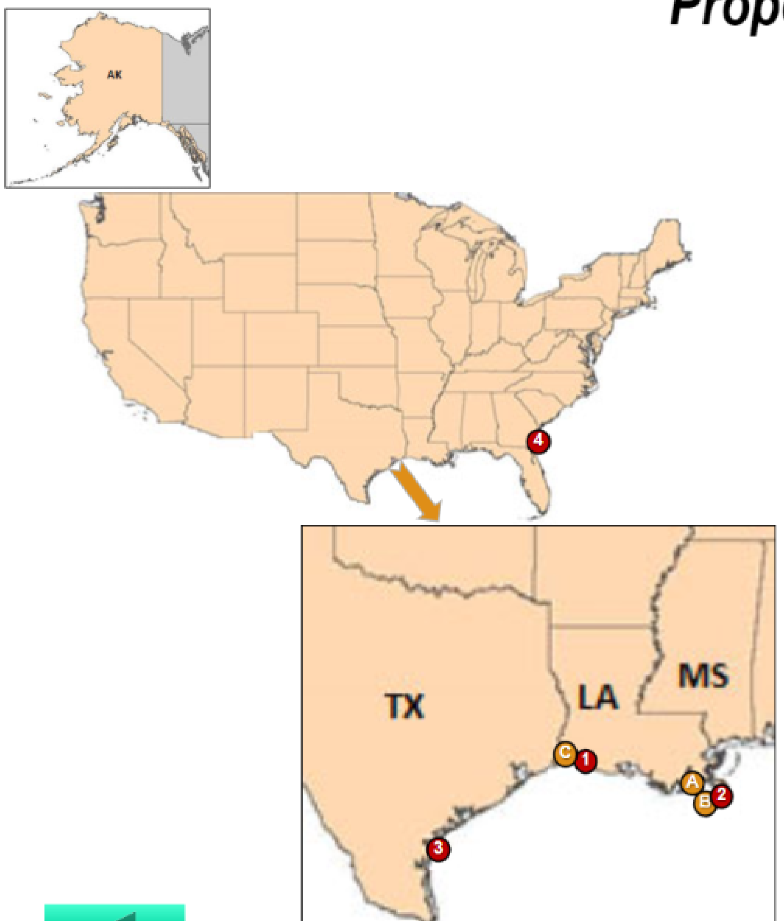
APPROVED - NOT UNDER CONSTRUCTION - MARAD/Coast Guard
A. **Gulf of Mexico:** 1.0 Bcfd (Main Pass Energy Hub)
B. **Gulf of Mexico:** 1.4 Bcfd (TORP Technology-Bienville LNG)

As of September 26, 2023
No updates since previous issuance

https://www.ferc.gov/natural-gas/lng

FERC Jurisdictional LNG Facilities - Proposed

United States LNG Export Terminals
Proposed



PROPOSED TO FERC

Pending Applications:

1. **Cameron Parish, LA:** 3.96 Bcfd (Venture Global CP2 Blocks 1-9) (CP22-21)
2. **Plaquemines Parish, LA:** 0.45 Bcfd (Venture Global Plaquemines) (CP22-92)
3. **Corpus Christi, TX:** 0.45 Bcfd (Cheniere Corpus Christi Midscale Trains 8-9) (CP23-129)
4. **Elba Island, GA:** 0.06 Bcd (Elba Liquefaction Optimization Project) (CP23-375)

Projects in Pre-filing:

A. **LaFourche Parish, LA:** 0.69 Bcfd (Port Fourchon LNG) (PF17-9)
B. **Plaquemines Parish, LA:** 2.76 Bcfd (Delta LNG - Venture Global) (PF19-4)
C. **Sabine, LA:** 0.9 Bcfd (Cheniere/Sabine Pass – Stage 5 Expansion) (PF22-2)

U.S. Jurisdiction & Status

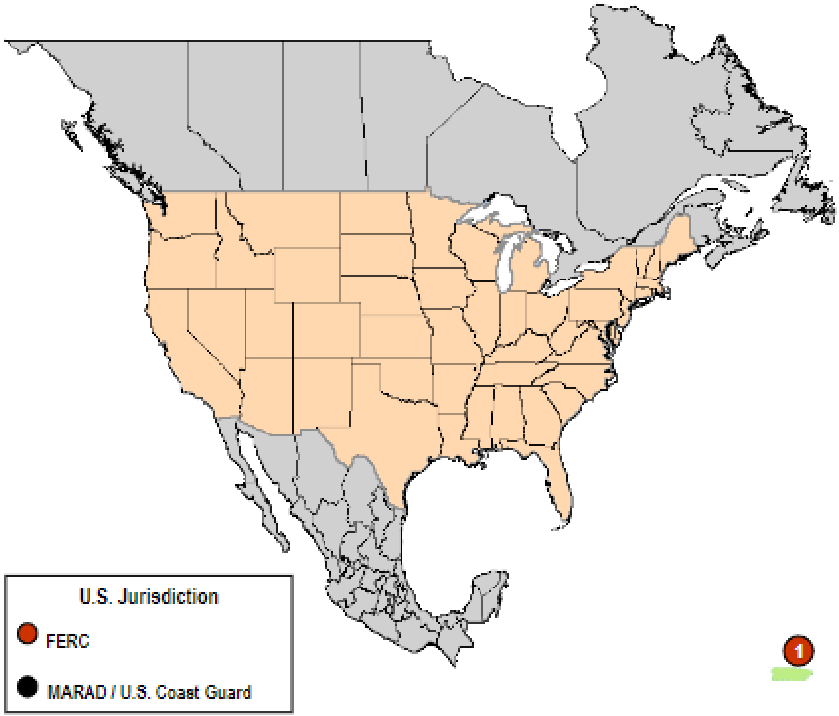
- FERC - Pending Applications
- FERC - Projects in Pre-filing

As of October 10, 2023
No updates since previous issuance

https://www.ferc.gov/natural-gas/lng

FERC Jurisdictional LNG Facilities - Proposed

United States LNG Import Terminals
Proposed



PROPOSED TO FERC
1. **San Juan, PR:** .217 Bcfd (New Fortress Energy – NFEnergía) (CP21-496)*

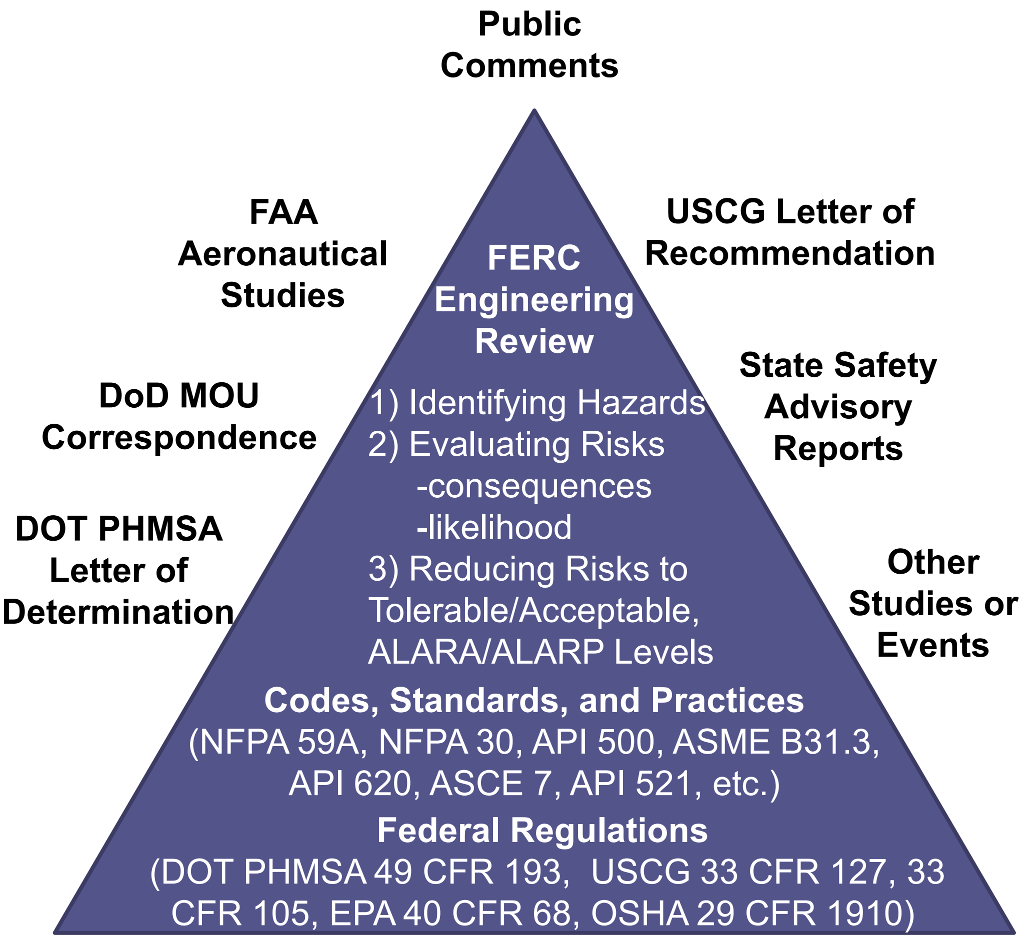
PROPOSED TO U.S.-MARAD/COAST GUARD
None

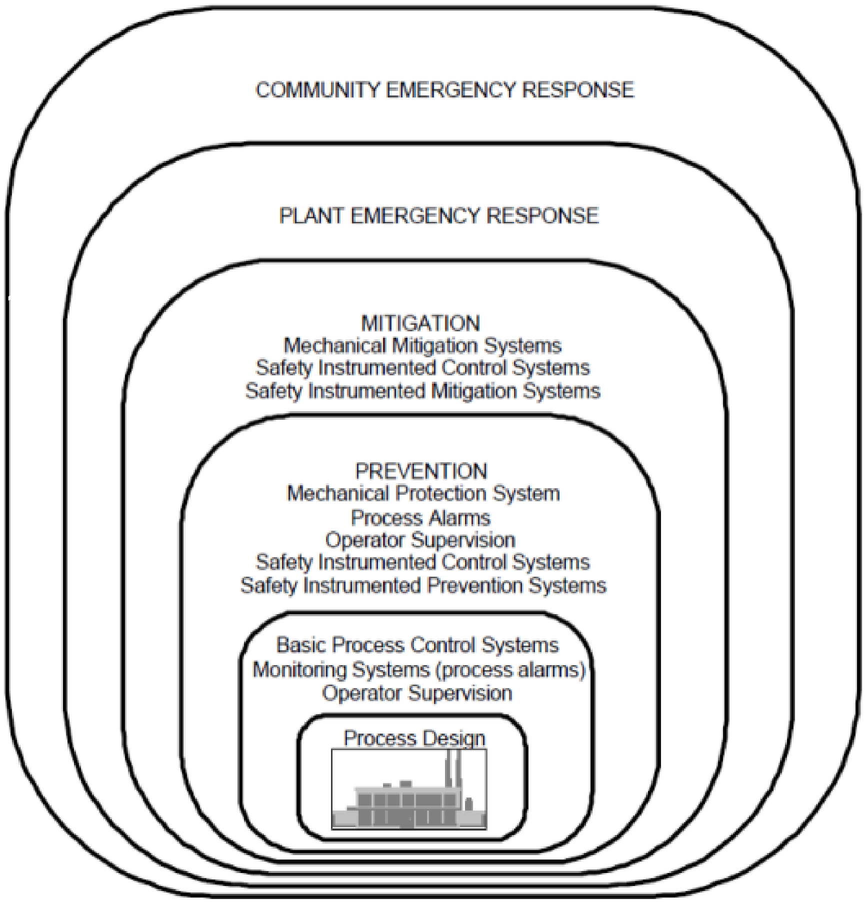
* Already in operation but undergoing additional FERC review per Commission Order on Show Cause under CP20-466.

As of September 26, 2023
No updates since previous issuance

https://www.ferc.gov/natural-gas/lng

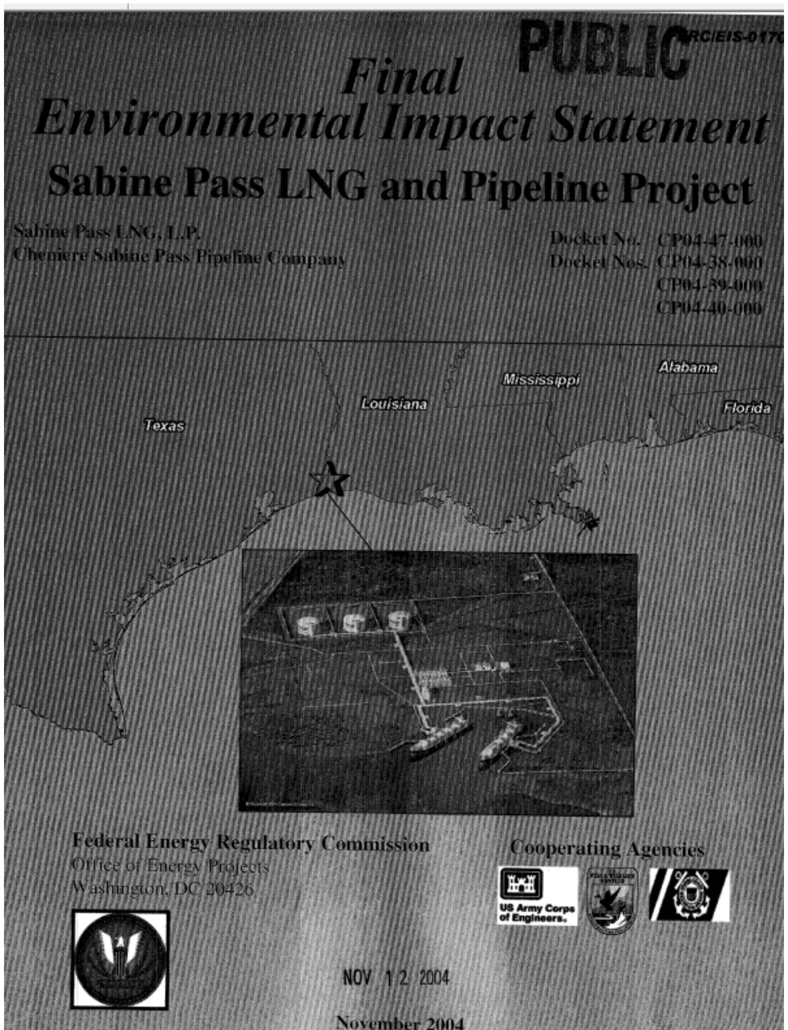
FERC DLNG Engineering Reviews and Inspections focus on Independent Preventative and Mitigative Layers of Protection





Layers of Protection-IEC 61511

National Environmental Policy Act (NEPA) Document



Commission Orders

In addition, conditions 124 through 127 shall apply **throughout the life** of the LNG Terminal facilities:

125. The facility shall be subject to regular FERC staff technical reviews and site inspections on at least an **annual basis** or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, Commonwealth shall respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted.

126. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from offsite vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tank, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also shall be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" shall be included in the semi-annual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance at the LNG facilities.

128. Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases; fires; explosions; mechanical failures; unusual over pressurization; and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) shall be reported to the FERC staff. In the event that an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made immediately, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to the FERC staff **within 24 hours**. This notification practice shall be incorporated into the liquefaction facility's emergency plan. Examples of reportable hazardous fluids-related incidents include:

a. fire;

b. explosion;

c. estimated property damage of $50,000 or more;

d. death or personal injury necessitating in-patient hospitalization;

e. release of hazardous fluids for 5 minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure-limiting or control devices;

i. a leak in an LNG facility that contains or processes hazardous fluids that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operating pressure or

Pre-Inspection Letters and Operational Inspections

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DLNG/LNG 1
Cove Point LNG, LP
Docket Nos. CP01-76-000,
CP05-130-000, and CP13-113-000
§375.308(x)

May 5, 2023

VIA Electronic Mail

Frank Brayton, Director LNG Operations
Cove Point LNG, LP
frank.brayton@bhegts.com

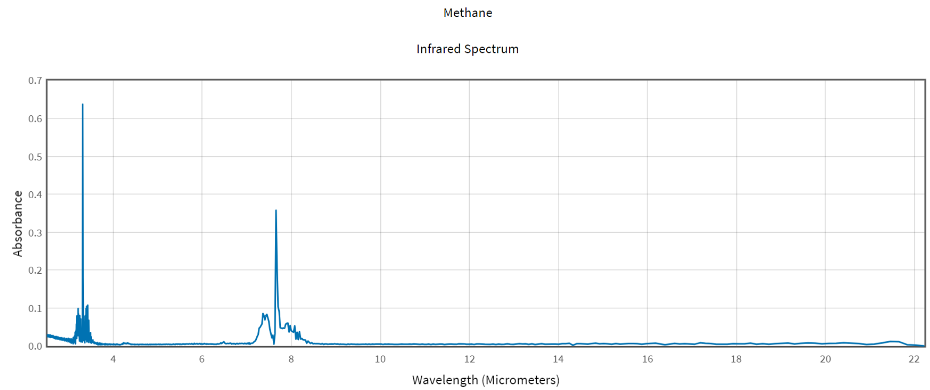
Re: Annual Post-Authorization Review and Site Inspection

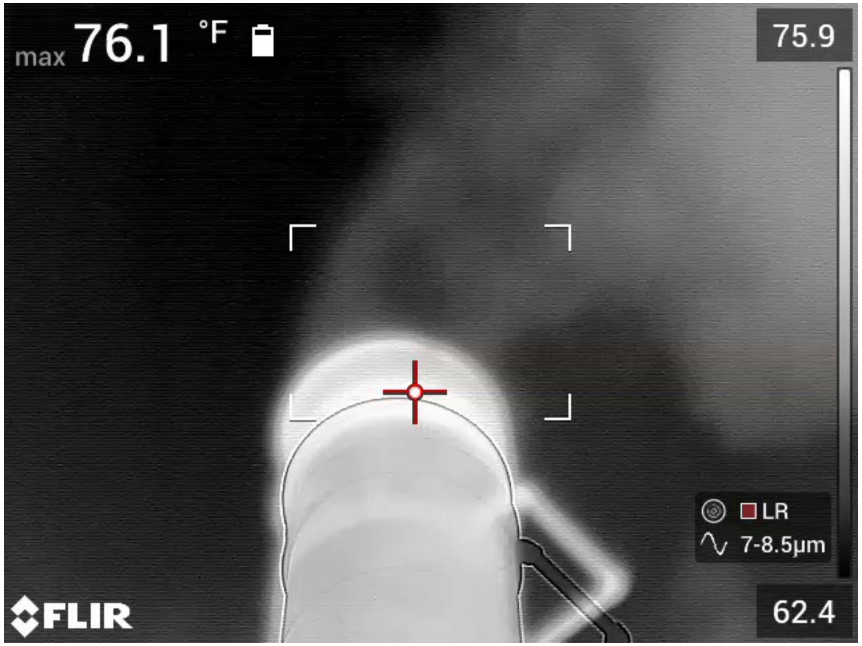
Dear Mr. Brayton:

The Commission staff plans to conduct its technical review and site inspection of the Cove Point LNG facility near Cove Point, Maryland, on August 22-23, 2023. Please provide the following information on the Cove Point LNG facility:

1. Describe any abnormal operating conditions at the facility since the last FERC inspection/review (July 12-14, 2022). Abnormalities shall include but not be limited to: stratifications or rollover; geysering; cold spots on the storage tanks; relative movement of the inner vessel; negative pressures (vacuum) within the storage tanks; higher than predicted boil-off rates; storage tank vibrations and/or vibrations in associated cryogenic piping; pipe movement including spring hanger position indicator(s) outside of normal range; leaking or inoperative isolation valves; significant equipment or instrumentation malfunctions or failures; non-scheduled maintenance or repair (and reasons thereof); and vapor or liquid releases; and any LNG shipping problems". (Note: Events previously reported in the Semi-Annual Operational Reports need not be re-described.)

2. Provide a list of all Federal (other than FERC), state, and local agencies inspections since the last FERC inspection/review, and provide the associated documents, recommendations, and/or reports. Identify all design, operating, maintenance, and security conditions which have been imposed or specific recommendations by these agencies/companies to improve or enhance the



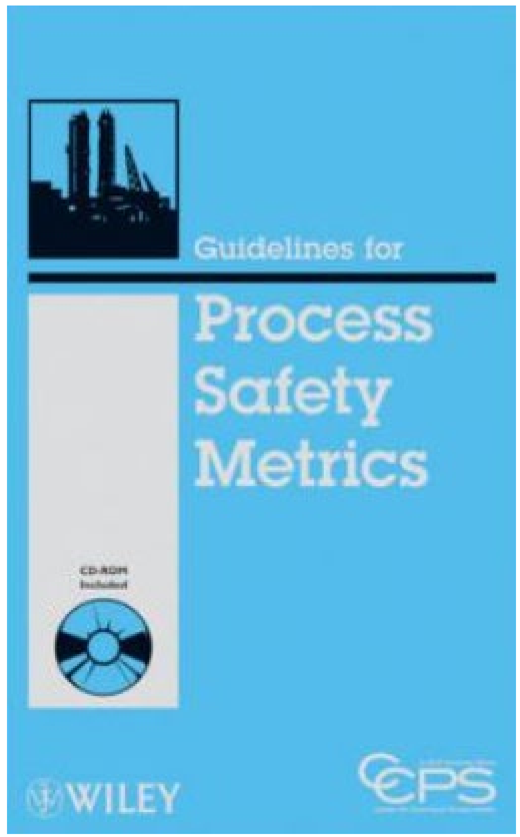


Q: What leaks and releases are FERC DLNG Staff most interested in from ***safety*** perspective for Incident Notifications, Semi Annual Reporting, and Operational Inspections? A: Lagging and Leading Indicators

Process Safety Performance Indicators for the Refining and Petrochemical Industries

ANSI/API RECOMMENDED PRACTICE 754
THIRD EDITION, AUGUST 2021

API American Petroleum Institute



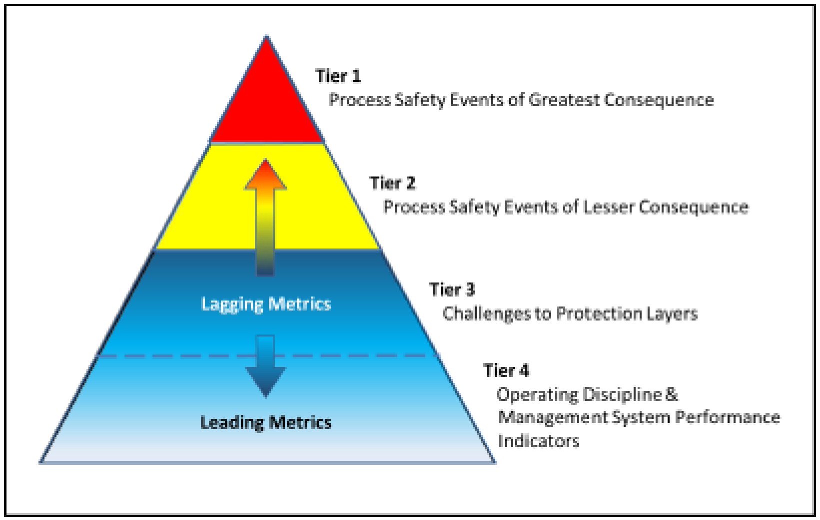
IOGP International Association of Oil & Gas Producers

REPORT 456 | MAY 2023

Process safety – Recommended practice on Key Performance Indicators

API 754/AIChE CCPS/IOGP 456 Tier 1 and 2 (Lagging Indicators) and Tier 3 and 4 (Leading Indicators)

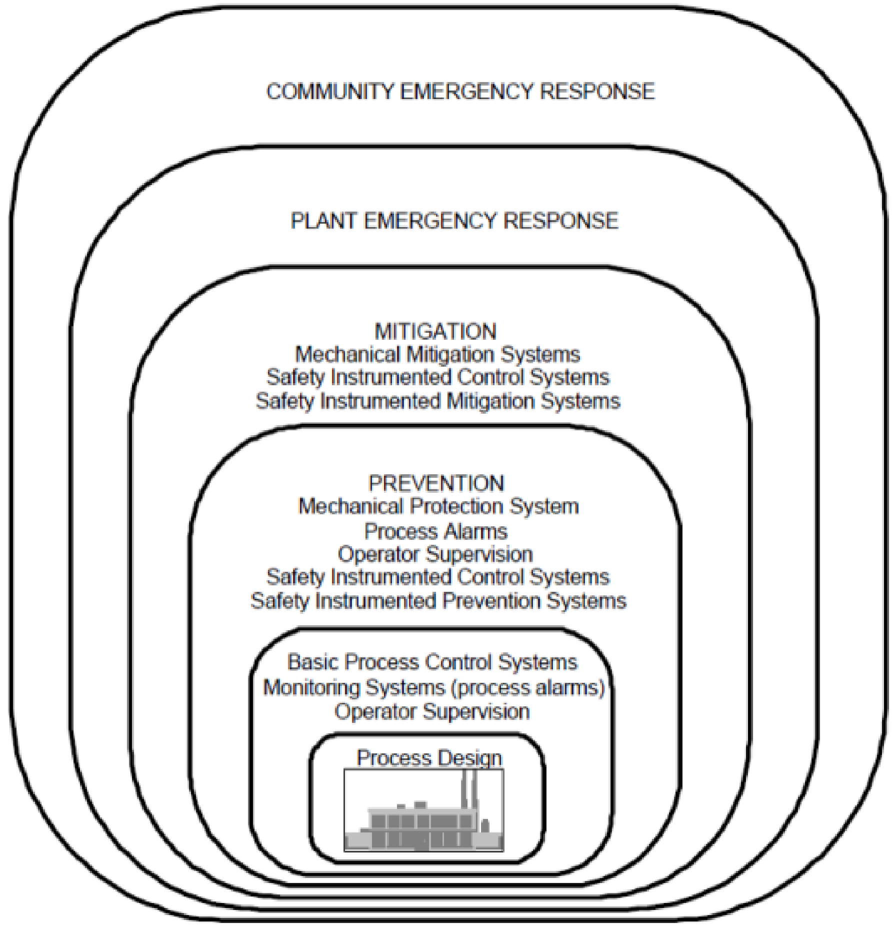
Process Safety Metrics: Guide for Selecting Leading and Lagging Metrics



Notes:
- Tier 3, Challenges to Protection Layers; includes near miss incidents
- Tier 4, Operating Discipline & Management System Performance Indicators; includes proactive evaluations and continuous improvement efforts, such as operational discipline surveys [8], management reviews [7], process safety management system audits [9], and field observations (e.g., behavior-based observations).

Figure 1

The Incident Triangle: Tiers and Their Corresponding Metric Types



API 754/AIChE CCPS/IOGP 456 Tier 1 and 2 (Lagging Indicators)

Consequence	PSE Level: Tier 1	PSE Level: Tier 2
Injury to employee or contractor	Fatality and/or Lost Workday Case ('days away from work' or 'lost time injury')	Recordable occupational injury (restricted work case or medical treatment case)
Injury to third party	Fatality, or injury/illness that results in a hospital admission	None
Impact to the community [a]	Officially declared community evacuation or community shelter-in-place including precautionary community evacuation or community shelter-in-place	None
Fire or explosion [b]	Fire or Explosion resulting in greater than or equal to $100,000 of direct cost to the Company	Fire or Explosion resulting in greater than or equal to $2,500 of direct cost to the Company

a Community evacuation/shelter-in-place would apply only to onshore facilities with public receptors that could potentially be exposed to impact from the release.

b For a fire or explosion, the classification should be done on the fire or explosion direct cost not the release rate. Fire or Explosion takes precedence over release rate in this case.

	PSE level: Tier 1	PSE level: Tier 2
An engineered pressure relief (PRD, SIS or manually initiated emergency depressurization) device or an upset emission from a permitted or regulated source discharge, either directly to atmosphere or to a destructive device (e.g., flare, scrubber)	Event is a Tier 1 PSE if it resulted in the consequences listed in Table E.1, regardless of the quantity released, or Event results in a: 1. rainout, or 2. discharge to a potentially hazardous location, or 3. on-site shelter-in-place[a] or on-site evacuation, excluding precautionary on-site shelter-in-place or on-site evacuation, or 4. public protective measures including precautionary public protective measures **and** the quantity discharged equals or exceeds any Tier 1 threshold in Tables E.4, 5 or 6	Event is a Tier 2 PSE if it resulted in the consequences listed in Table E.1, regardless of the quantity released, or Event results in a: 1. rainout, or 2. discharge to a potentially hazardous location, or 3. on-site shelter-in-place[a] or on-site evacuation, excluding precautionary on-site shelter-in-place or on-site evacuation, or 4. public protective measures including precautionary public protective measures **and** quantity discharged equals or exceeds any Tier 2 threshold in Tables E.4, 5 or 6

These thresholds for the amount of material released are based on Tier 1 and 2 categories from API RP 754, which are in turn based on international UNDG Packing Groups.

a Mustering offshore would be considered 'shelter-in-place' only if it was undertaken to separate people from a potentially hazardous atmosphere and if engineered protective features of the muster location were needed, in the event, to allow those mustering to shelter safely.

Material hazard classification (with example materials)	Tier 1: Outdoor release	Tier 1: Indoor release	Tier 2: Outdoor release	Tier 2: Indoor release
Flammable Gases, e.g. • hydrogen • methane, ethane, propane, butane • natural gas • ethyl mercaptan	≥500 kg (1,100 lbs) (TRC 5)	≥50 kg (110 lbs) (TRC 5)	≥50 kg (110 lbs) (TRC 5)	≥25 kg (55 lbs) (TRC 5)
Flammable Liquids with Boiling Point ≤35 °C (95 °F) and Flash Point <23 °C (73 °F) – e.g. • liquefied petroleum gas (LPG) • liquefied natural gas (LNG) • isopentane	≥500 kg (1,100 lbs) (TRC 5)	≥50 kg (110 lbs) (TRC 5)	≥50 kg (110 lbs) (TRC 5)	≥25 kg (55 lbs) (TRC 5)
Flammable Liquids with Boiling Point >35 °C (95 °F) and Flash Point <23 °C (73 °F), e.g. • gasoline/petrol, toluene, xylene • condensate • methanol • >15 API Gravity crude oils (unless actual flashpoint available)	≥1,000 kg (2,200 lbs) or ≥7 bbl (TRC 6)	≥100 kg (220 lbs) or ≥0.7 bbl (TRC 6)	≥100 kg (220 lbs) or ≥0.7 bbl (TRC 6)	≥50 kg (110 lbs) or ≥0.35 bbl (TRC 6)
Combustible Liquids with Flash Point ≥23 °C (73 °F) and ≤60 °C (140 °F), e.g. • diesel, most kerosenes • <15 API Gravity crude oils (unless actual flashpoint available)	≥2,000 kg (4,400 lbs) or ≥14 bbl (TRC 7)	≥200 kg (440 lbs) or ≥1.4 bbl (TRC 7)	≥200 kg (440 lbs) or ≥1.4 bbl (TRC 7)	≥100 kg (220 lbs) or ≥0.7 bbl (TRC 7)
Liquids with Flash Point >60 °C (140 °F) released at a temperature at or above its flash point, e.g. • asphalts, molten sulphur • ethylene glycol, propylene glycol • lubricating oil • drilling mud	≥2,000 kg (4,400 lbs) or ≥14 bbl (TRC 7)	≥200 kg (440 lbs) or ≥1.4 bbl (TRC 7)	≥200 kg (440 lbs) or ≥1.4 bbl (TRC 7)	≥100 kg (220 lbs) or ≥0.7 bbl (TRC 7)
Liquids with Flash Point >60 °C (140 °F) and ≤ 93°C (200°F) released at a temperature below its flash point, e.g. • some drilling muds • some marine diesel	Not applicable	Not applicable	≥1,000 kg (2,200 lbs) or ≥7 bbl (TRC 8)	≥500 kg (1,100 lbs) or ≥3.5 bbl (TRC 8)

Note 1: Companies may need to provide more detailed guidance on hydrocarbon mixtures or other gases or liquids specific to their operations. Refer to API RP 754, Annex G (Application of Threshold Release Categories to Multicomponent Releases) for guidance on how to properly determine the threshold quantity for mixtures.

Note 2: It is recognized that threshold quantities given in kg or lbs and bbl are not exactly equivalent. Companies should select one of the pair and use it consistently for all recordkeeping activities.

DOT PHMSA Incident Database FERC Jurisdictional - Lagging Indicators

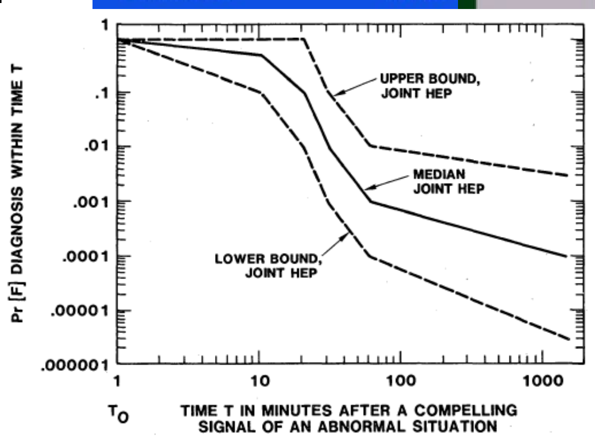
Total Reported	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Operators	20	20	20	20	20	20	20	21	21	
Plants	24	24	24	24	25	25	25	26	26	223 plant years
Incidents	2	1	0	2	3	3	4	1	2	18
Fatalities	0	0	0	0	0	0	0	0	0	0
Injuries	1	0	0	0	0	0	0	0	0	1
Evacuated	168	50	0	0	0	0	0	0	0	218
Damage $MM	46.5	<.01	0	<.01	34.2	0.125	2.64	<.01	85.1	168.8
MMcf Released	168	2	0	0	12	2	8	<1	11	204
Released >1100 lb	1	1	0	0	3	2	2	0	2	11
Released >110 lb	1	1	0	0	3	2	2	1	2	12
Ignited/Fire	1	0	0	1	0	0	3	0	1	6
Explosion	1	0	0	1	0	0	0	0	1	3

Layer of Protection General Design Basis/Assumptions

All layer reliability and effectiveness are contingent on operating and maintenance procedures and training for corrosion, ESD tests, PRV tests, firewater tests, etc. commensurate with SIL requirements.

Preventative/Mitigative Layers of Protection ***Commonly*** Assumed Design ***Durations*** vs 5 min incident reporting duration requirement.

- Operator actions
  - Assumed SIL1 (90% reliability) if 10 min available to intervene after alarm to take clear action prior to loss of containment or after detection of release
  - Assumed SIL1 or demonstrated SIL 2 (90-99% reliability) if 60 min available to intervene after alarm to take clear action prior to loss of containment or after detection of release
- SIS initiated ESD
  - Assumed SIL 1 (90% reliability) for single device/PLC/etc. and SIL 2 or SIL3 (99-99.9% reliability) for multiple redundant devices/PLCs/etc. if 10 min or less available to intervene prior to loss of containmer or after detection of release. Higher reliabilities and less times need to be demonstrated.
- Pressure Relief Devices
  - Assumed SIL 1 or demonstrated SIL 2 (90-99% reliability) for mitigating over-pressurization within design basis (e.g., NFPA 59A, API 521, etc.).
- Depressurization/Blowdowns
  - Assumed SIL 1 or demonstrated SIL2 (90-99% reliabilit if within design basis (e.g., API 521) in 15 min or less



Layer of Protection General Design Basis/Assumptions

Mitigative Layers of Protection ***Commonly*** Assumed Design ***Durations*** vs 5 min incident reporting requirement

- Electrical area classification
  - Assumed SIL 1 (90% reliability) if explosionproof, pressurized/purged, non-incendive and within design basis (e.g., API 500, NFPA 497 and FERC requirements)
  - Assumed SIL 2 (99% reliability) if intrinsically safe and within design basis (e.g., API 500, NFPA 497 and FERC)
- Ventilation
  - Assumed SIL 1 (90% reliability) if demonstrated within design basis (e.g., NFPA 59A, NEC, FERC)
- Siting Releases
  - Assumed SIL 2 (99%) reliability for releases within design basis (e.g., NFPA 59A) for releases of 10 min or less assuming SIL 1 Operator initiated shutdown/isolation in 10 min or ESD automatic shutdown within 10 min. Less times need to be demonstrated with SIL 2 ESD.
- Spill Containment Passive Protection
  - Assumed SIL 2 (≥99% reliability) contingent on SIL 2 shutdown/isolation per above if demonstrated within design basis (e.g., NFPA 59A, NFPA 30 and FERC requirements) for largest container(s); 10 min or less for largest flow from any single line; and typically, 60 min or less for largest flow from < 6-inch diameter release
- Hazard Detection, Shutdown, & De-inventory
  - Demonstrated (SIL 1) (90% reliability) if demonstrated within design basis (e.g., ISA 84.00.07 and FERC) for 10 min or less for releases that extend offsite or lead to cascading damage offsite; and typically, 10 min or more for largest flow from <2-inch diameter release
- Low Temperature Passive Protection
  - Assumed SIL 2 (99% reliability) if demonstrated within design basis (e.g., ISO 20088-1 15-60 min, FERC)
- Jet Fire Passive Protection (structural, ESD valves, ESD cabling, etc.)
  - Assumed SIL 2 (99% reliability) if demonstrated within design basis (e.g., ISO 22899-1 15-120 min, FERC)
- Pool Fire Passive Protection (structural, ESD valves, ESD cabling, etc.)
  - Assumed SIL 2 (99% reliability) if demonstrated within design basis (e.g., UL 1709 60-120 min, FERC)
- Emergency Response Evacuation
  - Assumed or demonstrated SIL 1 or SIL 2 (e.g., Evacuation Time Estimates) within 60-120 min
- Firewater
  - Assumed SIL 1 (90% reliability) if demonstrated within design basis (e.g., NFPA 59A 120 min supply, FERC)

FERC Layer of Protection General Design Basis/Assumptions – Lagging/Leading Indicators

Mitigative Layers of Protection ***Commonly*** Assumed Design ***Releases*** based on Codes and Standards

- Electrical area classification Class 1 Div 2 NFPA 497 and API 500 1 lb-mol/min corresponds to:
  - 16 lb/min **16 lb/min*5 min=80 lb < 110 lb Tier 2** LFL from 1/8-inch diameter at -260F/100 psig)
  - 28 lb/min (0.21 kg/sec) for ethylene, (e.g., 100 ft to ¼ LFL from 5/32-inch diameter at -74F/100 psig)
  - 30 lb/min (0.22 kg/sec) for ethane, (e.g., 100 ft to ¼ LFL from 11/64-inch diameter at -39F/100 psig)
  - 44 lb/min **44 lb/min*5 min=220 lb > 110 lb Tier 2** from 13/64-inch diameter at 64F/100 psig)
- Ventilation per NFPA 59A and NFPA 69 release rate assumed/demonstrated
- Jet Fire Passive protection per standard ISO 22899-1 and 2 correspond to:
  - 0.3 kg/sec (40 lb/min) from 17.8 mm (0.7-inch) natural gas
- Low temperature passive protection standard ISO 20088-1 correspond to:
  - 250 L (66 gal) or 200 kg (440 lb) liquid nitrogen released over 90 seconds (i.e., <2.2 kg/sec or <1 gpm or 290 lb/min) from 100 mm (4-inch) diameter at 1000 m (3 ft) height
- Spacing/Plant Layout corresponds to:
  - 25-120 ft to LFL and 100-225 ft to ½ LFL, 25-175 ft to 30 kW/m^2 and 50-225 ft to 5 kW/m^2 from 1-inch diameter LNG at 1-500psig (25-500 gpm or 100-2,100 lb/min or 1-16 kg/sec)
  - 175-250 ft to LFL and 350-750 ft to ½ LFL, 50-325 ft to 30 kW/m^2 and 75-450 ft to 5 kW/m^2 from 2-inch diameter LNG at 1-500psig (100-2,000 gpm or 420-8,400 lb/min or 3-65 kg/sec)
  - 450-775 ft to LFL (1000-1400 ft to ½ LFL), 125-600 ft to 30 kW/m^2 and 150-825 ft to 5 kW/m^2 from 4-inch diameter LNG at 1-500psig (450-7,850 gpm or 1,900-33,000 lb/min or 14-250 kg/sec)
- Siting, Hazard Detection, Firewater, Vapor Fencing, Emergency Response (i.e. onsite vs offsite) corresponds to:
  - <6-inch diameter LNG at 1-500 psig is <775 ft to LFL and <1400 ft (~0.25 mi) to ½ LFL, <600 ft to 30 kW/m2 and <825 ft to 5 kW/m2 (<7850 gpm or<250 kg/sec)
- Spill containment corresponds to:
  - Typically, <2 inch release for API 620/625/376 LNG storage tanks
  - largest flow from single line with n+1 pumps at runout for 10 min; typically 60,000 gpm from 36-inch diameter LNG at <100 psig (typically also <6 inch release for 1 hour)
- Pool Fire Passive protection standard UL1709
  - 65,00 BTU/ft^2-hr (204 kW/m^2) total heat flux and 2000F (1100C) within 5 min

DOT PHMSA Incident Database FERC Jurisdictional – Lagging/Leading Indicators

Total Reported	2014	2015	2016	2017	2018	2019	2020	2021	2022	TOTAL
Incidents	2	1	0	2	3	3	4	1	2	18
First Detected by Operators	2			1	2		3		2	10
First Detected by DCS/SIS		1			1	1	1	1		5
First Detected by FGS				1		2				3
Detection Time (min)	<1,<1	<2		<1,<1	5, 20, NR	<1,<1, <1	<1,NA, NR, <1	41	<1, 420	<1-420
Emergency Shutdown	2	1		1	2	2	1	1	1	11
ESD Time (min)	<1,<1	2		<1	5, 43	<1,<1	1	1	<1	<1- 43
Isolated/De-inventory Time (min)	NR	NR		NR	NR	NR	NR	7	343	7-343
Emergency Response On Scene (min)	NR	NR		NR	NR	NR	NR	8	5	5-8
Fire Suppressed (min)	NR	NR		NR	NR	NR	10	23	30	10-30
Evacuated	168	50	0	0	0	0	0	*	*	0-168
Evacuation Time (min)	NR	NR		NA	NA	NA	NA	NA	79	79
All Clear Time (min)	NR	NR		NA	NA	NA	NA	30	450	30-450

1/8-inch release

safe venting, but not environmentally permitted

Contrast to EPA LDAR Requirements

- 40 CFR 60 National Standards of Performance for New Stationary Sources (NSPS) Subparts:
  - OOOO Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011 and on or Before September 18, 2015
  - OOOOa Standards…After September 18, 2015 *(and on or before November 15, 2021)*
  - *OOOOb Standards…after November 15, 2021*
  - *OOOOc Standards…Existing Resources On or before November 15, 2021*
  - fugitive emissions constitute any visible emission observed using optical gas imaging (OGI) or an instrument reading of **500 parts per million** (ppm) or greater using Method 21 of appendix A-7 to this part
  - applicable to certain equipment

Possible criteria relative to EPA LDAR Requirements

Notification Protocols for LNG Facility Releases			
Release Type	**Isolation or Shutdown Time**	**Repair Time**	**FERC Notification Protocols**
Leak < 1 %vol LEL[a] (500 ppm-v)	None	None	None
Confirmed 1 %vol LEL ≤ Leak < 25 %vol LEL[b] of leaked substance (500 ppm-v to 12,500 ppm-v)	Process shutdown may not be required if leak can be isolated and repaired within 15 days OR if leak repair does not require isolation or process shutdown because of low severity	15 days or less	FERC Annual Ops Inspections (via Work Order audit)
Gas concentrations[c, d] greater than or equal to 1 %vol LEL and less than 25 %vol LEL equivalent of released product (i.e., below first high set point based on gas detector and likely gases present in area)	Process shutdown may not be required, but leak cannot be isolated and repaired within 15 days and isolation in the leak area is required within 15 days of leak and at or before time of scheduled to repair	> 15 days (scheduled)	FERC Semi Annual Reports (abnormal condition)
Confirmed Leak ≥ 25 %vol LEL of leaked substance of 5 minutes or more resulting in equal to or greater than 5 lb-mol or results in a fire, explosion, injury, death, damage of $50,000 or more, emergency shutdown, or other example provided in condition.(≥ 12,500 ppm-v) 1ooN gas detectors equal to or greater than 25 %vol LEL equivalent of released product (i.e., at or above first high set point) confirmed as flammable release for ≥ 5 min	Initiate shutdown and/or isolation immediately upon confirmation of 25 %vol LEL or higher flammable concentrations present near or at release source. [e]	Repair time will vary based on severity of leak	FERC Semi-Annual Report (if or if not faulty detector) FERC Incident Reporting (if not faulty detector)

[a] Point gas detectors measure gas concentrations in %vol LEL or %vol LFL. Open path detectors measure gas concentrations in LFL-meters (LFL-m). This table only displays %vol LEL but would also be applicable to equivalent %vol LFL and LFL-m readings as discussed in note b.

[b] NFPA 59A (2019) Sections 16.4.2.2 and 16.4.2.3 specify no more than 25 %vol LFL and 1 LFL-m as first alarm set point and no more than 50 %vol LFL and 3 LFL-m as second alarm set point. In addition, Section 15.5.3(3) specifies an automatic shutdown in the marine transfer area at 50 %vol LFL. Note that NFPA 59A (2019)'s first alarm set point slightly differs from EPA's LDAR requirements to report at 20 %vol LEL (10,000 ppm-v).

[c] Gas detectors can be calibrated to detect various hydrocarbons such as methane (the primary component in LNG), ethane, ethylene, propane, butane, etc. Based on the types of hydrocarbons present, each LNG facility would conservatively calibrate gas detectors to ensure %vol LEL of all hydrocarbons do not exceed the first alarm point (typically ~25 %vol LEL) and second alarm point (typically ~50 %vol LEL).

[d] This table discusses notification protocols for flammable gas releases. Similar notification protocols are required for toxic gas releases, oxygen deprivation, low temperature conditions, and presence of other hazards such as fires, explosions, etc.

[e] After a release is detected, the preference would be to first confirm a release with CCTV cameras (if can be seen). If cannot be seen visually with CCTV, personnel should scan the

Potential Research Ideas

- Gap analysis between existing LDAR programs, such as EPA LDAR and state administered programs, and potential DOT PHMSA LDAR program goals
  - Coverage of LNG facilities by type (e.g., baseload vs peakshaving vs satellite , marine terminal vs storage, etc.)
  - Coverage of new and existing LNG facilities by construction timeframe (e.g., <8/23/2011, 8/23/2011-9/18/2015, 9/18/2015-11/15/2021, >11/15/2021, etc.
  - Coverage of LNG facilities by equipment type (e.g., tanks, etc.)
- Adequacy or synergy in leveraging existing programs, such as API 754/AIChE CCPS/IOGP 654, and existing FERC reporting, EPA LDAR and state administered programs to fulfill DOT PHMSA LDAR program and reduce duplication.
  - Establishing acceptable methods (e.g., OGI vs Method 21), measurement point(s)/location(s), frequencies, and thresholds (visible vs 500 ppm and 10,000-12,500 ppm vs 110 lb vs 1 lb/mol-min) for environmental vs safety reporting
- Technological Improvements to determine concentration and/or flow rates using existing OGI technologies instead of whatever is visible or derived from specific concentrations from Method 21 (i.e., portable “sniffing” detectors at surface of leak)
  - Some OGI Vendors have their own software to quantify emissions based on the pixels in video images. Their algorithms can determine the density and rate of a gas plume and provide a leak rate. These methods have regulatory approval in Canada but are not widely used in the US.
  - Some users apply correlations to Method 21 concentrations to get a flow rate, but the accuracy is questionable (e.g., 500ppm ~ 1e-5 lb/min, 25,000ppm ~ 50%LEL~0.001 lb/min, 1,000,000ppm ~ 100%vol =“pegged” value ~0.005 lb/min depending on source). Bagging is an alternative method, but has challenges too.

Questions?

BOO!

Happy Halloween